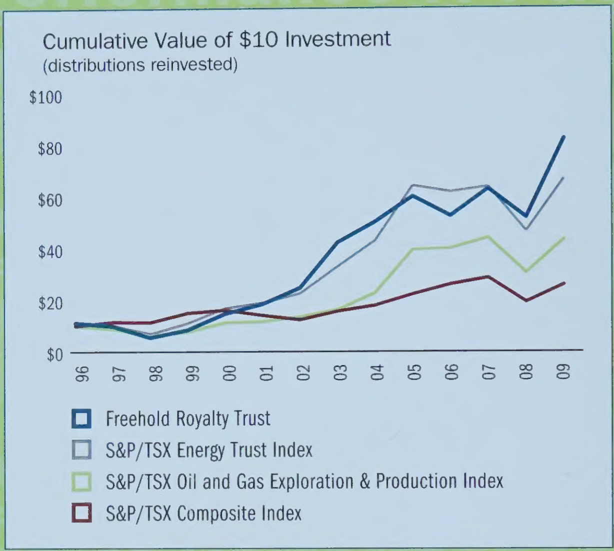
Freehold
ROYALTY TRUST

2009 Annual Report

A Pattern of Performance

Contents

A Pattern of Performance



The assets we acquired with the $264 million proceeds of our initial public offering in November 1996 have performed very well for over 13 years, supported by an experienced management team who have managed those assets for more than a quarter century. We have augmented our holdings over the years with complementary acquisitions. To December 31, 2009, we've distributed $795 million, or $20.53 per Trust Unit (more than double the IPO price of $10.00), generating a 15.5% compound annual return.

Profile

Freehold's primary focus is acquiring and managing oil and gas royalties. The majority of our production comes from royalty assets (mineral title lands and gross overriding royalties).

Freehold's Trust Units (FRU.UN) trade on the Toronto Stock Exchange in Canada.

Highlights

($000s, except as noted)	**2009**	2008	2007
Gross revenue	**119,965**	204,116	152,184
Net income (loss)	**31,741**	109,956	(1,192)
Per Trust Unit, basic and diluted ($)	**0.63**	2.23	(0.02)
Cash provided by operating activities	**95,659**	179,252	119,641
Per Trust Unit ($)	**1.91**	3.63	2.43
Funds generated from operations (1)	**95,085**	171,282	121,008
Per Trust Unit ($)	**1.90**	3.47	2.46
Distributions declared	**70,480**	143,749	94,545
Per Trust Unit ($) (2)	**1.40**	2.91	1.92
Long-term debt, December 31	**45,000**	140,000	178,000
Capital expenditures	**15,491**	12,992	12,167
Net property and royalty acquisitions	**9,539**	7,693	90,456
Trust Units outstanding, December 31 (000s)	**57,503**	49,459	49,317
Land holdings, gross acres (000s)	**2,386**	2,375	2,380
Undeveloped land, gross acres (000s)	**648**	651	589
Reserves, net proved plus probable (Mboe) (3)	**24,054**	25,374	27,963
Reserve life index (years)	**9.7**	9.8	9.5
Average daily production (boe/d) (3)	**7,302**	7,804	8,484
Operating netback ($/boe) (3)	**39.61**	65.18	43.54

(1) See non-GAAP measures on page 45.

(2) Based on the number of Trust Units issued and outstanding at each record date.

(3) See conversion of natural gas to barrels of oil equivalent (boe) on page 45.

The success of our business model is so predictable, it's easy to overlook.

Message to Unitholders

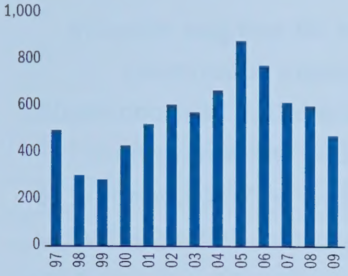
What were the highlights of 2009?

Improving oil prices throughout the year, together with our oil-weighted product mix and the low cost structure of our royalty production, combined to deliver strong netbacks. Distributions were adjusted early in the year to reflect a lower-price environment and we were able to raise them during the year as oil prices increased. Although we paid out less than half of what we distributed in 2008 (when we benefited from record oil prices), we nevertheless delivered a 13.3% cash-on-cash return for the year.

We spent $25 million on development activities and acquisitions in 2009. These activities added 1.4 MMboe of net proved plus probable reserves, replacing approximately 50% of 2009 production at an all-in finding, development and acquisition (FD&A) cost of $18.86 per boe (including changes in future development capital). We achieved a one-year recycle ratio of 2.1 times the capital invested, and a three-year average recycle ratio of 1.9 times.

In December, we improved our already strong balance sheet with a $115 million equity offering. This was only our third equity offering in 13 years, and we were pleased by the market's response and by the confidence demonstrated not only by the participation of our largest Unitholder, CN Pension Trust Funds, but also by the underwriters' exercise of the full 15% over-allotment option. Net proceeds were used, initially, to reduce long-term debt and, subsequently, to fund $49 million in royalty acquisitions.

Drilling On Our Royalty Lands
(gross wells drilled)



Since 1996, industry operators have drilled over 7,200 new wells on our royalty lands – at no cost to us.

What impact did the slowdown in industry drilling have on your royalty lands?

Industry activity levels were certainly muted compared to 2008. Overall, 55% fewer wells were drilled in 2009, and the average utilization rate for Canadian drilling rigs was at an all time low of 26%. As expected, drilling on our royalty lands was also down; consequently we saw a modest decline in production and reserves.

On the upside, weak industry conditions also created opportunities for us, as we recently completed two royalty acquisitions, adding approximately 363,000 gross acres of land, 1.7 MMboe of reserves, and 525 boe per day of production for 2010. The acquired royalty interests have strong netbacks because production is unencumbered by operating and capital costs and third party royalty expenses. The transactions involved the creation of 5% overriding royalties, with mutual benefits. The sale proceeds provided the vendors with an immediate source of funds for ongoing exploration and development, and Freehold benefits from current production as well as future production from new wells. We will continue to pursue these types of opportunities to grow our royalty production.

Is there future development potential on your royalty lands?

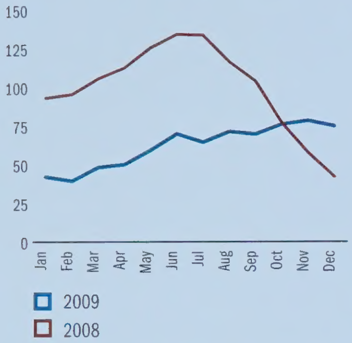
Our royalty lands encompass about 2.2 million gross acres, including more than 600,000 gross acres of undeveloped land. To date, development on our lands has reflected activity levels across the Western Canada Sedimentary Basin, and we expect that trend will continue.

Advances in drilling and completion technologies have the potential to revitalize oil development in the basin, substantially increasing production and recoverable reserves from mature producing oilfields, such as the Cardium oil trend in west central Alberta. We have significant exposure to this and other resource plays across our entire land base, particularly in areas south of the North Saskatchewan River, where we own significant mineral title lands.

Why don't you develop your royalty lands on your own?

When the Trust was formed in 1996, we acquired all of the producing royalty lands held by Canpar Holdings Ltd., while Canpar retained the non-producing deeper rights. In other words, virtually all of our original royalty lands were already leased to third parties. Most of these leases remain in effect as long as the lands continue to produce (subject to the lease provisions). One such provision enables us to issue an offset notice to the lessee to prevent development on adjacent lands from draining the reserves underlying our lands. These notices require the lessee to drill on our lands in a timely manner, pay a penalty through a compensatory royalty, or surrender the respective rights.

Average WTI Oil Price
(US$/bbl)



Average AECO Natural Gas Price
(Cdn$/Mcf)

The oil and gas industry appears “cautiously optimistic” that commodity prices will strengthen further in 2010, leading to increased drilling activity.

Over the years, our unleased mineral title acreage has grown – through lease expiries, defaults, and the acquisition of additional unleased mineral title lands – and we now have over 100,000 unleased acres. About two-thirds of this acreage is in southeast Saskatchewan. Over the past four years, we have selectively chosen to participate (take a working interest position) with industry partners to develop these lands, most notably along the Bakken trend. Since 2005, we have participated in the drilling of 28 (7.7 net) Bakken wells on these lands, including our first two 100% wells in 2009. This activity has been successful in adding value for our Unitholders. We achieve high netbacks because our share of production is royalty free. Given our large land position spanning most of the basin, there is potential to employ this strategy in other areas in the future.

What is your outlook for 2010?

Overall, the outlook for crude oil is more favourable than for natural gas. Markets for heavy oil remain robust due to strong refinery demand for this product type. Winter weather has increased heating demand throughout North America, and natural gas markets have responded with modest price increases. Although these factors are positive in the short-term, we believe that the road to full economic recovery will be long and bumpy, with continued commodity price volatility.

The oil and gas industry appears “cautiously optimistic” that commodity prices will strengthen further in 2010, leading to increased drilling activity. The Alberta government’s drilling and royalty incentives have been extended to March 31, 2011, which is also expected to have a positive impact on industry activity levels. While operators may focus on opportunities on Crown lands to take advantage of the incentives, we anticipate that increased activity will be reflected on our royalty lands eventually.

On our working interest properties, we plan to spend approximately $24 million in 2010. This represents a substantial increase over last year, as we plan to follow up on our success in southeast Saskatchewan with 15 (6.5 net) wells. We also anticipate an active program at Pembina Cardium Unit #9 as the operator, Penn West, continues with field redevelopment using horizontal infill drilling and multi-stage fracture stimulation.

We believe there may be further opportunities for us to acquire royalty interests as producers look to sell non-core oil and gas assets in order to fund their core exploration and development programs. Excluding any potential acquisitions, we are forecasting average production of 7,600 boe per day for 2010.

Is Freehold going to convert to a corporation?

In anticipation of the new SIFT tax beginning in 2011, our Board established a special committee of independent directors and charged them with a mandate to determine a course of action that maximizes Unitholder value. While a final determination has not yet been made, the committee has been examining the structures that our peers are adopting, assessing overall market sentiment including future access to capital, and considering complex legal and tax issues. While our organizational structure may change under the new tax regime, we intend to maintain our focus on oil and gas royalties. With our large, diversified asset base, low risk profile, low sustaining capital requirements, and high payout ratio, our primary goal has always been, and will remain, to enhance value for our Unitholders.

Any closing thoughts?

I would like to acknowledge and thank the employees of Rife (the Manager of the Trust) for their efforts on behalf of Freehold. I would also like to thank my fellow directors for their continued guidance, our Unitholders for their continued support, and industry operators for continuing to develop the lands from which we collect royalties.

Michael Okrusko will retire at the end of this year after serving for more than 28 years with Rife. The Board appointed him Senior Vice-President, Special Projects, effective March 1, 2010. Michael Stone, formerly General Manager, Land, has been appointed Vice-President, Land. Prior to joining Rife in 2008, he was Vice-President, Land with Real Resources Ltd., and has many years of land management experience.

The assets we acquired with the $264 million proceeds of our initial public offering in November 1996 have performed very well for over 13 years, supported by an experienced management team who have managed those assets for more than a quarter century. We have augmented our holdings over the years with complementary acquisitions, resulting in an overall net asset value of $13.06 per Trust Unit at December 31, 2009. We've distributed $795 million, or $20.53 per Trust Unit (more than double the IPO price of $10.00), generating a 15.5% compound annual return.

Looking to the future, we believe that our royalty lands continue to offer significant potential for future development that could extend production for many years.

On behalf of the Board of Directors of Freehold Resources Ltd.,

William O. Ingram
President and Chief Executive Officer
March 3, 2010

Joseph Neil Holowisky

We note with profound sadness the passing of our friend and colleague, Joe Holowisky, on February 20, 2010, after a 22-year battle with heart disease. Joe was a vital member of Rife's management team for more than 27 years. He was Freehold's Chief Financial Officer and then Senior Vice President, Special Projects until his retirement in January 2009. We extend our sincere condolences to his wife, Dianne, and his children, Todd and Gillian. He will be deeply missed by his Rife/Freehold family.

Management Team (from left to right):

Michael Okrusko, Senior Vice-President, Special Projects
William Ingram, President and Chief Executive Officer
Garry Bieber, Vice-President, Production
Michael Stone, Vice-President, Land
Frank George, Vice-President, Exploitation
Darren Gunderson, Vice-President, Finance and Chief Financial Officer

Strategic Focus

Since our initial public offering in 1996, we have consistently employed four simple strategies to sustain production and extend reserve life:

1. Maintain an aggressive audit program to ensure that royalties are correctly calculated and collected.
2. Pursue development opportunities to optimize reserves and production on our working interest properties.
3. Acquire additional assets with a bias toward royalty interests.
4. Maintain a conservative capital structure to provide maximum financial flexibility with respect to acquisitions and development expenditures, while maintaining appropriate distribution levels.

Corporate Responsibility

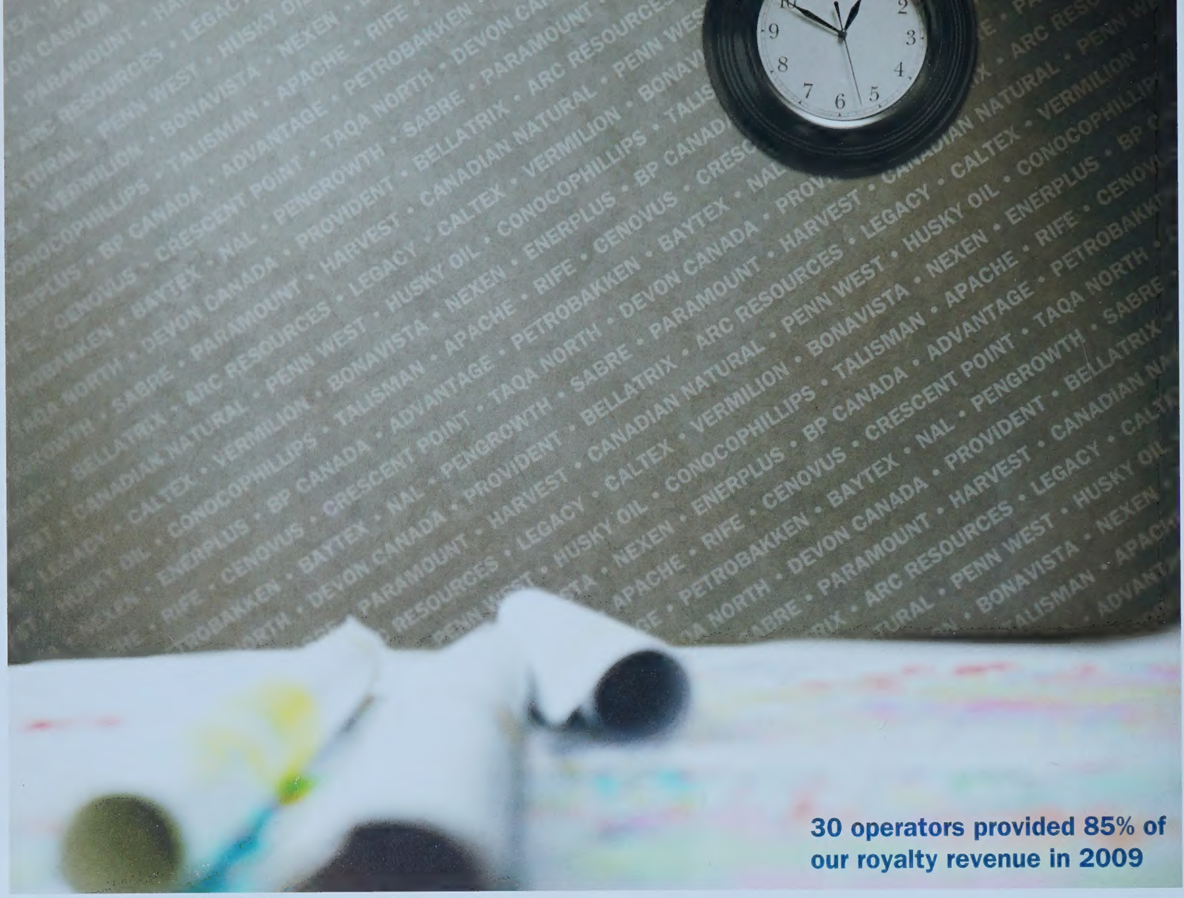
We believe it is important to meet the demand for energy in a safe and environmentally responsible manner. We promote a systematic approach to continuous improvement in environmental management and health, safety and social performance.

Freehold Royalty Trust has no employees. The Trust's operations are managed by Rife Resources Management Ltd. Rife and Freehold share a comprehensive environment, health and safety program that includes policies and procedures designed to protect the environment, health and safety of employees, contractors and the public. Rife assesses environmental, health and safety liabilities and exposure through pre-acquisition due diligence and regular site assessments and audits. Environmental, health and safety exposures are tracked and addressed with short and long-term initiatives. These initiatives include comprehensive training programs for employees and contractors; a contractor management program; engineering and purchasing controls; spill, release control, mitigation emergency preparedness; hazard and risk assessment; effective communication systems; integrity management; and incident investigation.

Rife also participates in the Alberta Human Resources and Employment's Partnerships in Health and Safety Program, and received a *Certificate of Recognition* (COR) after completing the required independent safety audits in 2006 and 2009. Rife will continue to participate in the Partnership program, which requires an external audit every three years. Rife also participates in the Canadian GHG Challenge Registry, Canada's only voluntary publicly-accessible national registry of greenhouse gas baselines, targets, and reductions. Rife was a *Gold Champion Level Reporter* in 2009.

All of Freehold's properties are operated by other companies, and we expect our operators to meet or exceed regulatory requirements. As a member of the Canadian Association of Petroleum Producers (CAPP), we also encourage our operators to participate and excel in the CAPP Stewardship Program by aligning their operations with industry best practices.

Freehold supports the community by donating to registered charities and not-for-profit organizations. We are especially supportive of local charitable organizations addressing education, health, and community services focused on the needs of children and families that will value and benefit from Freehold's annual funding commitment.



30 operators provided 85% of our royalty revenue in 2009

Assets and Operations

Freehold Royalty Trust owns one of the largest portfolios of oil and gas royalties in Canada. Our land holdings total 2.4 million gross acres extending from northeastern British Columbia to southern Ontario, the majority of which are royalty lands. We have royalty interests in more than 26,000 wells and receive royalty payments from over 200 industry operators. This diversity lowers our risk, while we benefit from industry drilling activity. As a royalty interest owner, we do not pay any of the capital costs to drill and equip the wells for production, nor do we incur costs to operate the wells, maintain production, and ultimately restore the land to its original state. The operators pay all of those costs and we simply receive a percentage of the production.

Freehold Royalty Trust is a proud owner of legacy lands originally owned by the Hudson's Bay Company

1670

Charles II, King of England, granted to the Company of Adventurers (Hudson's Bay Company) sole trade and commerce rights in, and title to, all of the lands encompassing the watershed of Hudson's Bay. This historic land grant covered 1.5 million square miles, nearly 40% of Canada today.

1867

Upon Confederation, the Hudson's Bay Company surrendered title to these lands in exchange for £300,000 Sterling and 1/20th of all agricultural land in western Canada. This gave the Hudson's Bay Company Section 8 and 3/4ths of Section 26 (the 8s and 26s) in most Townships south of the North Saskatchewan River between Winnipeg and the Rocky Mountains (approximately 4.5 million acres) – the HB Lands.

1926

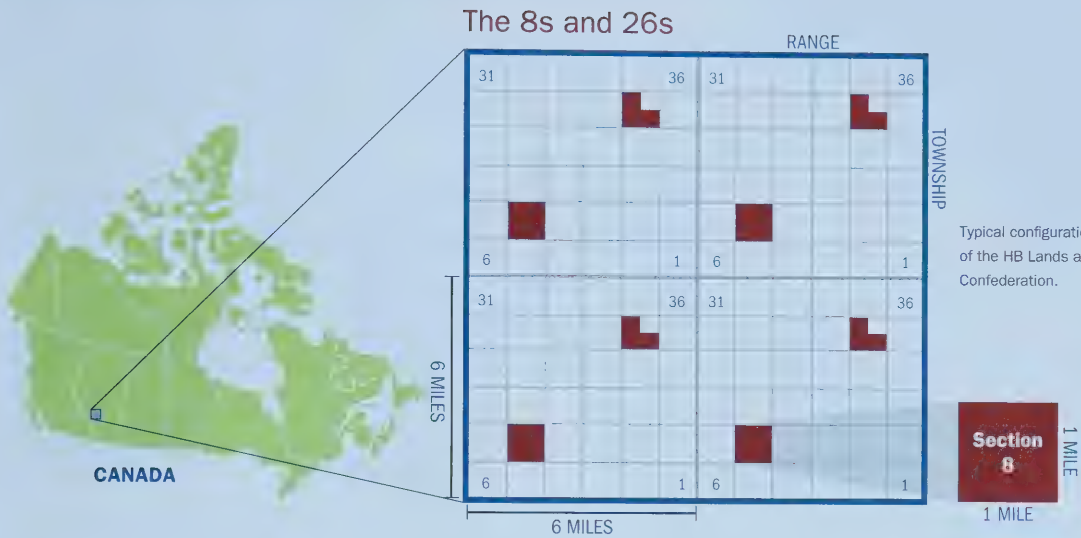
Hudson's Bay Company co-founded Hudson's Bay Oil and Gas Company Limited with exclusive right to lease all of the HB Lands in western Canada to explore for oil and gas.

1974

The Hudson's Bay Company sold its mineral title interests in western Canada to Siebens Oil & Gas Ltd.

1979

Canpar Holdings Ltd. (owned by the CN Pension Trust Funds) and Dome Petroleum Limited jointly acquired the assets of Siebens.



Typical configuration of the HB Lands after Confederation.

What is a Royalty?

A royalty is a payment to the royalty owner based on a percentage of the gross well production without the working interest owners' associated responsibility for any expenses.

There are two types of royalties – lessor royalties and overriding royalties.

- Lessor royalties represent the mineral title owner's share of production, free of production expenses. Mineral title lands are held in perpetuity. When a company wants to drill for oil or gas, it must negotiate for the mineral rights with the mineral title owner (the Crown or a freehold owner). When the mineral title owner leases those rights to a company to drill for oil or gas, it generally retains a percentage share of production, called a lessor royalty.
- Overriding royalties arise primarily from contractual arrangements between companies and are usually derived from working interests that expire when production ceases.

We own both mineral title rights and gross overriding royalties, but our mineral titles lands are our most valuable asset. Our ownership in mineral titles ranges from 10% to 100%. Leases provide for a royalty payment ranging from 10% to 22.5% of production. For example, if our ownership is 50% of the mineral title and the royalty rate applicable to the lease is 20%, then we are entitled to receive the proceeds from the sale of 10% of the oil or natural gas produced (50% x 20% = 10%).

1988

Amoco Canada Petroleum Company Ltd. acquired Dome Petroleum.

1993

Canpar and Amoco exchanged certain assets, whereby Canpar acquired increased mineral title ownership in the producing HB Lands originally acquired from Siebens.

1996

Canpar and Rife Resources Ltd. (private companies owned by the CN Pension Trust Funds) established Freehold Royalty Trust. Proceeds from Freehold's $264 million initial public offering were used to acquire all of Canpar's producing royalty interests (with Canpar retaining the non-producing deeper rights). Freehold also acquired several working interest properties from Canpar and Rife.

2001

Freehold acquired 129,000 gross acres of producing and undeveloped mineral title and gross overriding royalty interests in southeast Saskatchewan.

2005

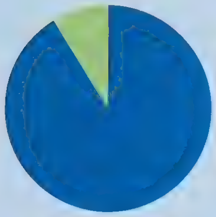
Freehold acquired Petrovera Resources from Canadian Natural Resources Limited, adding more than a million gross acres of mineral title and gross overriding royalty interests in western Canada and in Ontario. This acquisition more than doubled our royalty land holdings.

2010

Freehold continues to focus on acquiring and managing oil and gas royalties. Today, our total land holdings encompass 2.4 million gross acres, over 90% of which are royalty interests.

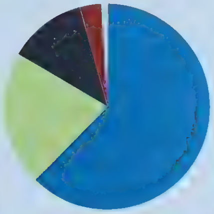
The most active drillers on our lands in 2009 included Cenovus (previously EnCana), ARC, Canadian Natural Resources, Rife, TAQA North, Enerplus, Husky, Devon, NAL, ConocoPhillips, Penn West, and Apache.

Land Holdings
(gross acres)



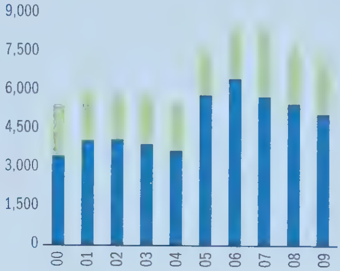
Working interest – 212,413
Royalty interest – 2,173,469

Land Holdings By Province
(gross acres)



Alberta – 1,493,335
Saskatchewan – 507,707
Ontario – 295,769
British Columbia – 80,788
Manitoba – 8,283

Average Daily Production
(boe/d)



Working interest
Royalty interest

skatoon

Regina

Winnipeg

Spotlight on Resource Plays

We have significant exposure to resource plays across our entire land base, particularly in oil-prone areas south of the North Saskatchewan River, where we own significant mineral title lands.

Bakken Resource Play, Saskatchewan

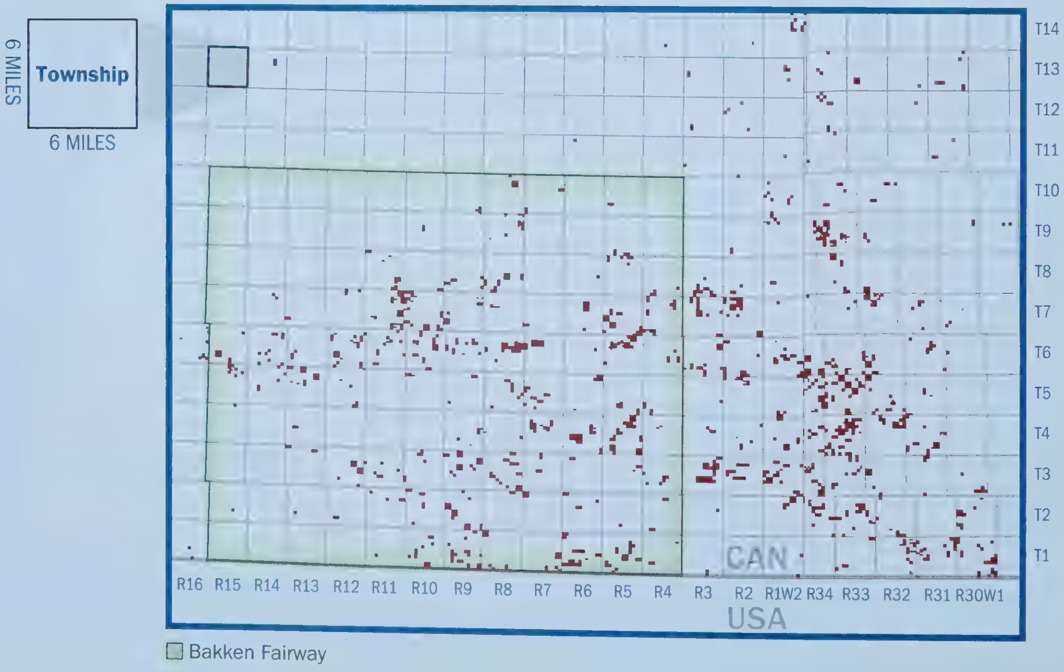
The Bakken oil play has been one of the driving forces behind the industry's growth in southeast Saskatchewan since 2004. Active drilling and the use of multi-stage fracture technology continue to expand the absolute size of the recoverable oil-in-place, making it the top resource play in western Canada. It also benefits from a favourable royalty regime implemented by the Saskatchewan Government to stimulate oil and gas investment in the province.

When the Trust was formed in 1996, we had minimal land holdings in southeast Saskatchewan. That changed in 2001, when we purchased 95,000 gross acres of mineral title lands. Today, the area is not only a significant royalty area for Freehold, but also our largest working interest property in terms of production.

On our mineral title lands within the Bakken fairway, we have title interests ranging from 10% to 100%, and working interests ranging from 2.5% to 100%. To date, lessees have drilled 37 Bakken wells on our mineral title lands. In 2005, we began to participate (take a working interest position) with industry partners, and over the past four years we have drilled 28 (7.7 net) Bakken wells. Our lessees and partners include Crescent Point, TAQA North, Penn West, PetroBakken, Villanova, Canadian Natural Resources, and Painted Pony.

The majority of our Bakken lands are unleased. In 2009, we drilled our first two 100% working interest Bakken wells on our 100% mineral title lands. We have identified over 100 potential (unrisked) Bakken drilling locations on our unleased mineral title lands that could provide an ample prospect inventory for several years. In 2010, we have allocated $14 million to development activities in southeast Saskatchewan. We plan to drill 15 (6.5 net) wells, the majority of which will target the Bakken.

Freehold's Land Holdings

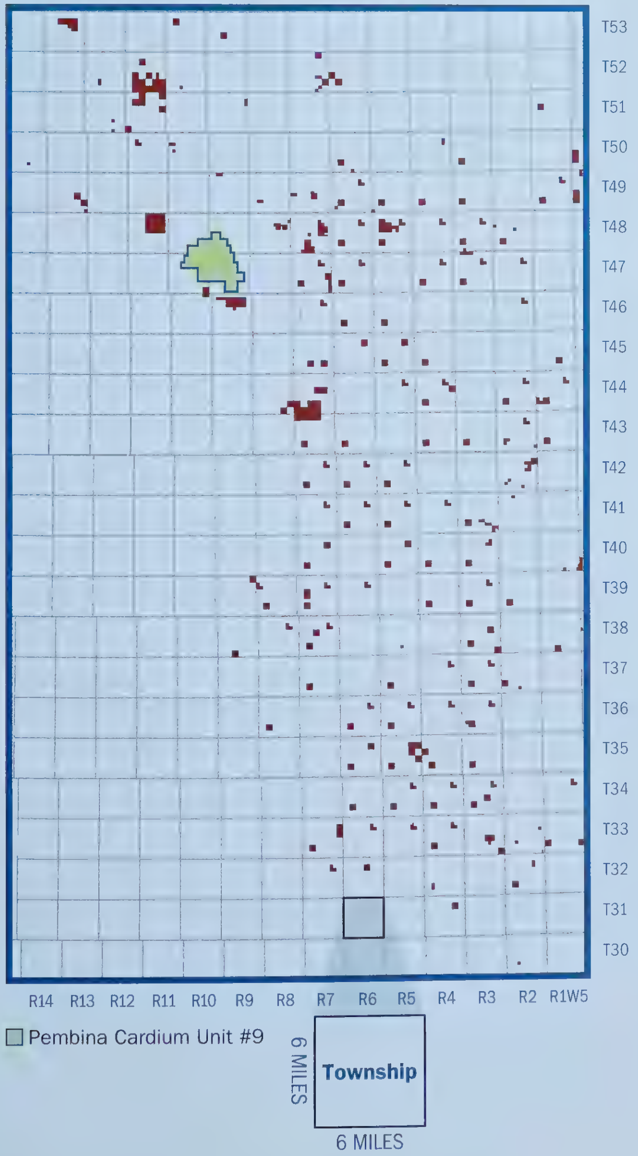


Cardium Resource Play, Alberta

Advances in drilling and completion techniques are creating large resource plays throughout the Western Canada Sedimentary Basin in low permeability reservoirs with large oil-in-place and low recovery rates. The most significant of these is the Cardium trend, which extends across 42 oil fields in west central Alberta and represents about 20% of the remaining reserves in the entire basin. The largest field by far is Pembina, discovered in 1953, with initial in-place reserves of 7.5 billion barrels. Two approaches are being used to unlock the potential of the Cardium. Some operators are using multi-fracture horizontal wells on the edges of the field where the reservoir is too thin or too tight to produce from vertical wells. Others are drilling in the main part of the field, targeting larger oil pockets. While there is much potential given the overall size of the resource, each pool will require a different approach and it may take many years to perfect the appropriate techniques.

On our royalty lands situated on the Cardium oil trend, we have title interests ranging from 27% to 100%. All of our royalty lands in this area are leased out to third parties, so we expect their activity to add to our royalty production, and reserves, when drilled. Operators currently active in the Cardium include ARC, NAL, Penn West, Petro-Canada (now Suncor), Devon, Bonterra and Enerplus.

Freehold's Land Holdings



Pembina Cardium Unit #9

In the Pembina Cardium Unit #9, we own a 9.97% working interest and a 0.6% royalty interest, which includes interests in 164 wells. This unit has an extremely long reserve life and has been under waterflood for more than 45 years. In 2008, the operator of the unit, Penn West, began studying the use of horizontal multi-stage fracture technology. Development in 2009 included a four-well pilot program and we have approved five horizontal wells (0.5 net) thus far for 2010. Penn West recently drilled a well in the unit that commenced production at rates in excess of 800 barrels of oil per day. For 2010, we have allocated $8 million of capital to this unit.

About Horizontal Drilling Technology and Resource Plays

Resource plays target known, regionally extensive but technically challenging oil and natural gas deposits. Many of these deposits were not considered economically recoverable until recently, when advances in horizontal drilling and new completion techniques began to be employed. Horizontal drilling is highly effective at providing maximum exposure to tight reservoirs. New wells typically exhibit a steep production decline, initially, and then produce for many years at low annual decline rates. A large drilling inventory is required to maintain stable volumes over the long run.

Through experience and repetition, the operator can improve well results by fine-tuning the drilling, completion, stimulation, and production techniques. Much like a manufacturing process, these improvements can drive down development costs and increase profitability. Although the initial capital outlay is greater for a horizontal well than for a vertical well, cost efficiencies are gained because a single horizontal well, with multiple staged fractures, can access as much of the reservoir as several vertical wells.

Asset Summary

Freehold's primary focus is acquiring and managing royalty interests, and our vast royalty interest acreage contributes the majority of our production and reserves.

We also own primarily small working interests in 100 non-operated oil and gas properties. The three largest of these are located in southeast Saskatchewan, at Hayter in east central Alberta, and the Pembina Cardium Unit #9 in western Alberta.

2009 Operational Highlights

	Royalty Interest	Working Interest	**Total Trust**
Land holdings (gross acres)	2,173,469	212,413	**2,385,882**
Undeveloped land (gross acres)	604,917	43,445	**648,362**
Capital expenditures ($000s)	–	15,491	**15,491**
Net property and royalty acquisitions ($000s)	9,539	–	**9,539**
Gross wells drilled	478	28	**506**
Net proved plus probable oil and gas reserves (Mboe)	18,557	5,497	**24,054**
Average daily production (boe/d)	5,147	2,155	**7,302**
Operating netback ($000s) [1]	81,880	23,697	**105,577**
Per boe ($)	43.59	30.12	**39.61**

(1) See Non-GAAP measures on page 45.

Royalty Acquisitions

Acquisitions are important to extend our production and reserve life. We recently completed two acquisitions that involved the assignment of existing overriding royalty interests to Freehold as well as the creation of new overriding royalties. Both acquisitions support our strategy of focusing on oil and gas royalties and are accretive, on a debt-adjusted per unit basis, to cash flow, production, reserves, and net asset value. The creation of overriding royalties provides benefits to both parties. For the vendors, the sale proceeds provide a source of capital to fund their ongoing development activities. For Freehold, the acquired royalty interests bring strong netbacks, as production is unencumbered by operating and capital costs and third party royalty expenses. The acquisitions also allow us to benefit from future development on the properties.

On December 21, 2009, we expanded our presence in the multi-zone prospective deep basin region of northwest Alberta. We acquired, for $10 million, royalty interests on approximately 43,200 gross acres, of which 26,400 are located in the Bigstone area. Reserves were independently evaluated at 0.3 MMboe proved plus probable, and have an estimated reserve life index of six years based on annualized 2010 production of 145 boe per day. Future opportunities on the Bigstone lands include liquids-rich, sweet natural gas and shallow, light Cardium oil.

On February 17, 2010, we acquired royalty interests on approximately 319,700 gross acres in Alberta, Saskatchewan, and British Columbia, for $39 million. Reserves were independently evaluated at 1.4 MMboe proved plus probable, and have an estimated reserve life index of just under nine years based on annualized 2010 production of 435 boe per day. As this acquisition occurred subsequent to year-end, these reserves were not included in our December 31, 2009 reserve evaluation. We anticipate further development on these lands over the next several years.

Net Proved Plus
Probable Reserves
(by product type)

Natural gas – 38%
Oil and NGL – 62%

Our reserves are oil-weighted and about one-third of our reserves are heavy oil.

Reserves and Net Asset Value

In 2009, we spent $25 million on development activities and acquisitions, adding 1.4 MMboe of net proved plus probable reserves (before 2009 production). We replaced approximately 50% of 2009 production at an all-in finding, development and acquisition cost of $18.86 per boe (including changes in future development capital). These activities resulted in a one-year recycle ratio of 2.1 times the capital invested, and a three-year average recycle ratio of 1.9 times.

Net Asset Value (1) (2)

($000s, except as noted)	**2009**	2008	2007
Present value of oil and gas reserves (3) (7)	**707,583**	730,659	711,624
Present value of potash reserves (4) (7)	**17,809**	27,807	14,317
Undeveloped land (5)	**79,408**	93,975	30,252
Reclamation fund (6)	**2,261**	1,827	1,788
Working capital (6)	**(3,082)**	(20,055)	11,219
Bank debt (6)	**(45,000)**	(140,000)	(178,000)
Asset retirement obligations (6)	**(7,160)**	(5,663)	(6,608)
Net asset value	**751,818**	688,550	584,592
Trust Units outstanding (000s)	**57,503**	49,459	49,317
Net asset value per Trust Unit ($)	**13.06**	13.92	11.85

(1) Net asset value (NAV) is a measure used widely within the investment community and in the oil and natural gas industry. It shows what is normally referred to as a 'produce-out' NAV calculation under which the Trust's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It does not represent a 'going concern' value and it should not be assumed that the present value of oil and gas reserves represent the fair market value of the reserves. Net asset value does not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

(2) Columns may not add due to rounding.

(3) Based on net proved plus probable reserves evaluated by Trimble Engineering Associates Ltd., before tax, discounted at 10%, and includes future capital expenditure expectations required to bring undeveloped reserves on production.

(4) Based on net proved plus probable reserves, before tax, discounted at 10%. Potash reserves, evaluated internally, are not subject to National Instrument 51-101.

(5) Evaluated by Seaton-Jordan & Associates Ltd.

(6) Financial information per Freehold's consolidated financial statements.

(7) Future net revenue values do not represent fair market value.

Management's Discussion and Analysis

The following discussion is management's opinion about our consolidated operating and financial results, including Freehold Resources Ltd., Freehold Royalty Trust, and Petrovera Resources (a general partnership) for the year ended December 31, 2009 and previous periods, and the outlook for Freehold based on information available as at March 3, 2010.

The financial information contained herein has been based on information in the consolidated financial statements, which have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the years ended December 31, 2009 and 2008 and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion and analysis should be read in conjunction with the audited financial statements and notes contained in this annual report. Discussion and analysis of fourth quarter events or items affecting our financial condition, cash flows, and results of operations is contained in our 2009 fourth quarter MD&A, which is incorporated by reference herein. Additional information about us, including our annual information form (AIF), is available on SEDAR at www.sedar.com and on our website at www.freeholdtrust.com.

This MD&A contains Non-GAAP measures and forward-looking statements; readers are cautioned that the MD&A should be read in conjunction with our disclosure under "Non-GAAP Measures" and "Forward-Looking Statements" included at the end of this MD&A.

Business Overview

Freehold Royalty Trust is structured as a mutual fund trust under the *Income Tax Act* (Canada). This enables us to return the majority of our income to Unitholders in a tax-effective manner. We receive revenue from oil and natural gas properties as reserves are produced over the economic life of the properties.

Strategy

We effectively manage our assets to consistently deliver attractive returns to Unitholders. Our goal is to be recognized as the preeminent royalty-focused oil and gas investment in Canada. We employ the following strategies to sustain production and extend reserve life:

- Maintain an aggressive audit program to ensure that royalties are correctly calculated and collected.
- Pursue development opportunities to optimize reserves and production on our working interest properties.
- Acquire additional assets with a bias toward royalty interests.
- Maintain a conservative capital structure to provide maximum financial flexibility with respect to acquisitions and development expenditures, while maintaining appropriate distribution levels.

The Royalty Advantage

Freehold Royalty Trust is pursuing the royalty advantage. We manage one of the largest portfolios of oil and gas royalties in Canada. Our royalty lands are geographically widespread, extending from northeastern British Columbia to southern Ontario. At December 31, 2009, our royalty land holdings encompassed approximately 2.2 million gross acres including over 600,000 gross acres of undeveloped land. Our mineral title lands (including royalty assumption lands), owned in perpetuity, cover 643,309 gross acres. We have gross overriding royalty interests on over 1.5 million acres.

We have royalty interests in more than 26,000 wells and we receive royalty income from over 200 industry operators. Royalty rates vary from less than 1% (for some gross overriding royalties) to 22.5% (for some lessor royalties). This diversity lowers our risk. Royalties offer the benefit of sharing in production revenue without exposure to the capital costs, operating costs, and environmental costs typically associated with oil and gas operations. On the majority of our production, we receive royalty income from gross production revenue (revenue before any royalty expenses and operating costs are deducted). Our high percentage of royalty production (70% in 2009) results in strong netbacks, which maximizes distributions to Unitholders.

We also hold working interests in 212,413 gross (25,413 net) acres. The majority of our working interest production comes from three properties in Alberta and Saskatchewan. We have various working interests in 97 other properties, which individually contribute less than 100 boe per day.

The accompanying netback analysis demonstrates the positive effect of the royalty advantage on our cash margins as production on our royalty lands yields higher operating netbacks than our working interest properties.

2009 Netback Analysis

($000s)	Royalty Interest	Working Interest	Total Trust
Gross revenue (1)	81,231	38,734	119,965
Royalty expense and mineral tax (2)	649	(3,382)	(2,733)
Net revenue	81,880	35,352	117,232
Operating expense	-	(11,655)	(11,655)
	81,880	23,697	105,577
($ per boe)			
Gross revenue (1)	43.24	49.24	45.01
Royalty expense and mineral tax (2)	0.35	(4.30)	(1.03)
Net revenue	43.59	44.94	43.98
Operating expense	-	(14.82)	(4.37)
Operating netback (3)	43.59	30.12	39.61

(1) Gross revenue includes potash, sulphur, lease rentals, processing fees, and interest income; excludes other income.

(2) Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.

(3) Operating netback is calculated by subtracting royalty and operating expenses from gross revenue.

Operating Netback

($ per boe)	**2009**	2008	2007
Royalty interest	**43.59**	69.33	47.49
Working interest	**30.12**	55.00	34.90
Total Trust	**39.61**	65.18	43.54

The Manager

We do not operate any of our oil and gas assets, nor do we have any employees. The Manager of the Trust is a wholly-owned subsidiary of Rife Resources Ltd., which is a wholly-owned subsidiary of the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). The Manager (Rife) also manages two private companies that are engaged in similar oil and gas operations. To manage these private companies and the Trust, Rife has assembled a larger, more diversified and more experienced staff than we could otherwise retain to manage our assets. Rife also ensures that the Trust receives priority to consider acquisition opportunities. We believe these organizational and synergistic benefits are advantageous to Unitholders. In addition, the management fees are paid in Trust Units, which we believe aligns the interests of the Manager with the interests of the Unitholders.

The Manager is responsible for the day-to-day management of the business of the Trust subject to the supervisory role of the Board. In particular, the Board makes significant operational decisions and all decisions relating to: (a) issuances of additional securities of the Trust; (b) acquisition and disposition of properties in excess of $5 million; (c) capital expenditures outside of approved budgets; (d) establishment of credit facilities; and (e) payment of distributions to Unitholders.

The management agreement has a three-year term and will automatically renew on November 26, 2010, unless terminated. In exercising its powers and discharging its duties under the management agreement, the Manager must exercise the degree of care, diligence, and skill that a reasonably prudent advisor and manager in respect of petroleum and natural gas properties in western Canada would exercise in comparable circumstances. The Manager recovers its costs and receives a quarterly management fee paid in Trust Units (see Related Party Transactions).

The Manager provides certain administrative and support services to the Trust, including those necessary to:

- Ensure compliance with continuous disclosure obligations under applicable securities legislation.
- Provide investor relations services.
- Provide to Unitholders all information to which Unitholders are entitled under the Trust Indenture.
- Call, hold, and distribute materials including notices of meetings and information circulars in respect of all necessary meetings of Unitholders.
- Determine the amounts payable from time to time to Unitholders and arrange for distributions to Unitholders.
- Determine the timing and terms of future offerings of Trust Units, if any.
- Determine the terms and conditions upon which the Trust may acquire additional royalties.
- Determine the terms and conditions upon which the Trust may from time to time borrow money.

Outlook

Business Environment

Industry activity levels remained muted in 2009. There were 55% fewer wells drilled overall in western Canada than in 2008, and the average utilization rate for Canadian drilling rigs was at an all time low of 26%.

An improving global economic outlook contributed to a gradual oil price improvement through 2009 and to date in 2010, although the benefit has been partly offset by a corresponding rise of the Canadian dollar. Markets for heavy oil remain robust due to strong refinery demand for this product type. Winter weather has increased heating demand throughout North America, and natural gas markets have responded with modest price increases. While these factors are positive in the short-term, we believe that the road to full economic recovery will be long and bumpy. Overall, the outlook for crude oil is more favourable than for natural gas and, with our oil-weighted production, Freehold is well positioned to continue to benefit from strengthening oil markets.

The Petroleum Services Association of Canada recently updated its 2010 Canadian drilling activity forecast and is “cautiously optimistic” that commodity prices will strengthen further in 2010, leading to increased drilling activity. The Alberta Government’s short-term stimulus plan to encourage conventional oil and natural gas activity in the province is also expected to have a positive impact on industry activity levels in the coming months. While operators may focus on opportunities on Crown lands to take advantage of the incentives, we anticipate that increased activity will be eventually reflected on our royalty lands.

2010 Plans

As previously announced, we recently acquired certain royalty interests for $49 million. We believe there may be opportunities for us to acquire additional royalty interests as producers look to sell non-core oil and gas assets in order to fund their core exploration and development programs.

On our working interest properties, we anticipate spending approximately $24 million in 2010. This represents a substantial increase over 2009, as we plan to accelerate development of our Bakken-prone title lands in southeast Saskatchewan. In addition, we anticipate an active program at Pembina Cardium Unit #9 as the operator, Penn West, continues with field redevelopment using horizontal infill drilling and multi-stage fracture stimulation. With additional production from our recent acquisitions and a larger capital program, we are forecasting average production of 7,600 boe per day for 2010; royalty interests are expected to account for 70% of this production. General and administrative costs will be higher than last year as a result of consulting fees related to our IFRS conversion project and the potential impact of the SIFT tax. Assuming participation in our distribution reinvestment plan (DRIP) remains level throughout the year, DRIP proceeds of approximately $24 million will be used to reduce debt and fund a portion of our capital program. As we are now issuing DRIP units from treasury, the weighted average number of Trust Units outstanding in 2010 is expected to be 58.4 million.

2010 Key Operating Assumptions

As at March 3, 2010		
Average daily production	boe/d	7,600
Average WTI oil price	US$/bbl	80.00
Average AECO natural gas price	Cdn$/Mcf	5.00
Average exchange rate	Cdn$/US$	0.96
Average operating costs	$/boe	4.30
Average general and administrative costs [1]	$/boe	3.20
Capital expenditures	$ millions	24.0
Proceeds from DRIP	$ millions	24.0
Long-term debt at year end	$ millions	53.7
Weighted average Trust Units outstanding	thousands	58,363
Estimated portion of distributions taxable as income	%	90 - 100%

(1) Excludes unit based and other compensation.

Distribution Policy

Our distribution policy takes into consideration forecasted cash provided by operating activities, debt levels, debt covenants, capital expenditures, and reclamation fund requirements. We have a depleting asset base, and ongoing development activities and acquisitions are necessary to replace production and add additional reserves. The success of these activities, along with commodity prices, are the main factors influencing the sustainability of our distributions. With the expectation that commodity prices will remain volatile, the regular monthly distribution rate is fixed at $0.14 per Trust Unit until further notice. We will continue to review our distribution policy monthly and make adjustments, if necessary, to ensure that the distribution level is in line with funds generated from operations.

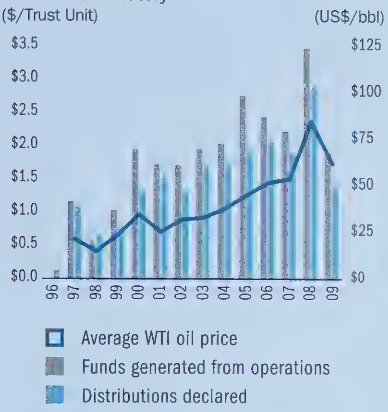
Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices (including light/heavy oil price differentials), foreign exchange rates, or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands since we do not know the future plans of the various operators. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as about one-third of our total boe production is heavy oil.

A sensitivity analysis of the potential impact of key variables on distributions to Unitholders is provided below.

Sensitivity Analysis

		Estimated Change in Distributions to Unitholders	
Variable	Change (+/-)	($000s)	($/Trust Unit)
WTI oil price	US$1.00/bbl	1,860	0.03
Light/heavy oil price differential	Cdn$1.00/bbl	1,753	0.03
AECO natural gas price	Cdn$0.25/Mcf	1,530	0.03
Exchange rate	0.01	1,408	0.02
Interest rate	1%	500	0.01
Oil and NGL production	100 bbls/d	2,605	0.04
Natural gas production	1,000 Mcf/d	1,765	0.03

Distribution History



Since the formation of the Trust in 1996, we have distributed 81% of funds generated from operations to our Unitholders.

Results of Operations

2009 Highlights

- Gross revenue declined 41%, mainly due to lower commodity prices. Average price realizations were $44.00 per boe, down 37%, and average production was 7,302 boe per day, down 6% from 2008. Net income declined substantially, to $31.7 million ($0.63 per Trust Unit).
- Cash provided by operating activities (including changes in non-cash working capital) fell 47%, reflecting lower realized prices and lower production volumes, while funds generated from operations declined 44%.
- Distributions for 2009 totalled $1.40 per Trust Unit, 52% lower than in 2008.
- Capital expenditures (working interests) totalled $15.5 million and net acquisitions (royalty interests) totalled $9.5 million.

Highlights

($000s, except as noted)	**2009**	2008	2007
Gross revenue	**119,965**	204,116	152,184
Revenue, net of royalty expenses	**117,232**	197,500	145,921
Net income (loss)	**31,741**	109,956	(1,192)
Per Trust Unit, basic and diluted ($)	**0.63**	2.23	(0.02)
Cash provided by operating activities	**95,659**	179,252	119,641
Per Trust Unit ($)	**1.91**	3.63	2.43
Funds generated from operations (1)	**95,085**	171,282	121,008
Per Trust Unit ($)	**1.90**	3.47	2.46
Total assets	**418,540**	452,275	504,200
Long-term debt	**45,000**	140,000	178,000
Total long-term liabilities	**91,998**	188,417	237,118
Distributions declared	**70,480**	143,749	94,545
Per Trust Unit ($) (2)	**1.40**	2.91	1.92

(1) See Non-GAAP Measures.

(2) Based on the number of Trust Units issued and outstanding at each record date.

Quarterly Performance and Trends

Our performance is directly influenced by commodity prices, which are determined by supply and demand factors, weather, seasonality, global political events, general economic conditions, and changes in Canadian/U.S. dollar exchange rates. Quarterly variances in revenues, net income, cash provided by operating activities, and funds generated from operations are caused mainly by fluctuations in commodity prices and production volumes. Crude oil prices are generally determined by global supply and demand factors, but the variances do not have seasonable predictability. Natural gas prices are significantly influenced by weather conditions and North American natural gas inventories.

Our financial results over the last eight quarters were influenced by the following significant factors:

- WTI crude oil prices exhibited significant volatility. After reaching record levels in mid-2008, the benchmark price fell significantly in the last half of 2008 as global economic conditions deteriorated. Low prices prevailed through the first quarter of 2009 and then improved through the remainder of 2009.
- Fluctuations in U.S. to Canadian dollar exchange rates also affected our oil price realizations, resulting in both positive and negative effects on our Canadian dollar oil revenues relative to the benchmark WTI, which is referenced in U.S. dollars.
- Heavy oil differentials narrowed considerably from historical levels. U.S. demand for Canadian heavy crude has risen as imports from Mexico and Venezuela have declined. Domestic demand for heavy oil is typically highest during the summer paving season.
- AECO natural gas prices also exhibited volatility. Natural gas markets strengthened briefly in mid-2008; however, with supply continuing to outstrip demand, prices continued to face downward pressure, falling to a 10-year low during the third quarter of 2009. Natural gas is a typically seasonal, weather-dependent fuel; demand is generally higher during the winter (for heating) and summer (for cooling), and lower during the spring and fall.
- We adjusted our monthly distributions in response to changing commodity prices. In April 2008, we raised the rate by $0.03 to $0.18 per Trust Unit, and raised it again in June 2008, to $0.25 per Trust Unit. We also declared an additional distribution of $0.35 per Trust Unit for 2008, which was paid to Unitholders on January 15, 2009. The distributions payable to Unitholders (current liability) at year-end 2008 was higher than at year-end 2009 because the additional distribution for 2008 was not paid until 2009. In January 2009, we lowered the rate to $0.10 per Trust Unit. As oil prices strengthened, we increased the rate to $0.12 per Trust Unit in August 2009, and increased it again in November 2009, to $0.14 per Trust Unit. We also declared an additional distribution of $0.06 per Trust Unit for 2009, which was paid in the fourth quarter.
- In 2007 and 2008, the oil and gas industry experienced rising costs due to strong economic growth. These inflationary pressures began to ease in late 2008 as weak commodity prices cooled industry activity levels and brought down power costs.
- Fluctuations in our Trust Unit price resulted in corresponding changes in unit based and other compensation, which is based in part on the closing unit price at each quarter end.
- Under Freehold's DRIP, commencing with the October distribution (payable on November 15, 2009), we began issuing DRIP Trust Units from treasury instead of purchasing them in the market. Also with the November 15, 2009 distribution payment, CN Pension Trust Funds, which owns approximately 23% of Freehold's Trust Units, began to participate in the DRIP. DRIP proceeds for the final two months of 2009 were $3.9 million.
- On December 10, 2009, Freehold closed an equity offering and issued 7.6 million Trust Units. Net proceeds of $110.5 million were used to reduce long-term debt.
- On December 21, 2009, we closed a $10 million royalty acquisition. The acquisition was funded through our existing credit facilities.

The accompanying table illustrates the fluctuations experienced over the past eight quarters and the resulting effect on our financial results. Discussion and analysis of fourth quarter events or items affecting our financial condition, cash flows, and results of operations is contained in our 2009 fourth quarter MD&A, which is incorporated by reference herein. Additional information about our quarterly results is provided in our interim reports, copies of which are available on SEDAR or on our website.

	2009				2008			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial ($000s, except as noted)								
Revenue, net of royalty expense	**33,966**	**29,435**	**28,516**	**25,315**	33,174	58,210	59,563	46,553
Distributions declared	**23,937**	**16,850**	**14,852**	**14,841**	54,387	37,050	30,114	22,198
Per Trust Unit ($) (1) (2)	**0.46**	**0.34**	**0.30**	**0.30**	1.10	0.75	0.61	0.45
Net income	**14,721**	**7,853**	**6,776**	**2,391**	13,374	36,772	36,163	23,647
Per Trust Unit, basic and diluted ($)	**0.29**	**0.16**	**0.14**	**0.05**	0.27	0.74	0.73	0.48
Cash provided by operating activities	**25,937**	**26,215**	**21,938**	**21,569**	41,672	57,380	46,379	33,821
Per Trust Unit ($)	**0.50**	**0.53**	**0.44**	**0.44**	0.84	1.16	0.94	0.69
Funds generated from operations (3)	**30,444**	**24,189**	**21,833**	**18,619**	26,942	51,977	53,183	39,182
Per Trust Unit ($)	**0.59**	**0.49**	**0.44**	**0.38**	0.55	1.05	1.08	0.79
Net property and royalty acquisitions	**9,539**	**-**	**-**	**-**	(782)	8,475	-	-
Capital expenditures	**4,435**	**7,368**	**1,661**	**2,027**	3,770	9,222	2,135	2,202
Long-term debt	**45,000**	**147,000**	**156,000**	**160,000**	140,000	141,000	151,000	169,000
Trust Units outstanding								
Weighted average (000s)	**51,483**	**49,543**	**49,495**	**49,460**	49,424	49,389	49,353	49,317
At quarter end (000s)	**57,503**	**49,582**	**49,531**	**49,495**	49,459	49,424	49,388	49,352
Operating ($/boe, except as noted)								
Daily production (boe/d)	**7,402**	**6,994**	**7,295**	**7,522**	7,779	7,613	7,674	8,152
Royalty interest production (%)	**69**	**71**	**71**	**70**	71	71	72	71
Average selling price	**51.09**	**44.01**	**42.99**	**37.85**	46.55	83.47	86.43	64.16
Operating netback (3)	**45.66**	**42.16**	**37.56**	**33.13**	42.14	79.14	81.21	59.18
Operating expenses	**4.22**	**3.59**	**5.39**	**4.27**	4.21	3.97	4.08	3.58
Working interest properties	**13.69**	**12.59**	**18.78**	**14.27**	14.31	13.51	14.37	12.54
General and administrative expenses	**2.38**	**2.35**	**2.12**	**3.98**	2.20	1.95	2.15	3.16
Benchmark Prices								
WTI crude oil (US$/bbl)	**76.19**	**68.30**	**59.62**	**43.08**	58.69	117.98	123.98	97.86
Exchange rate (Cdn$/US$)	**0.95**	**0.91**	**0.86**	**0.80**	0.83	0.96	0.99	1.00
Edmonton Par crude oil (Cdn$/bbl)	**76.56**	**71.50**	**65.90**	**49.66**	63.21	121.85	126.07	97.50
Western Canada Select/Hardisty (Cdn$/bbl)	**67.65**	**63.75**	**60.71**	**42.54**	47.72	103.87	103.32	76.70
Light/heavy oil differential (Cdn$/bbl) (4)	**8.91**	**7.75**	**5.19**	**7.12**	15.49	17.98	22.75	20.80
AECO natural gas (Cdn$/Mcf)	**4.23**	**3.02**	**3.66**	**5.62**	6.78	9.24	9.35	7.13
Unit Trading Performance								
High ($)	**16.28**	**17.00**	**15.18**	**11.76**	18.43	24.35	24.40	19.29
Low ($)	**14.02**	**12.75**	**8.70**	**6.87**	9.15	16.01	17.51	14.55
Close ($)	**15.09**	**16.24**	**13.85**	**8.90**	10.49	17.10	23.99	18.04
Volume (000s)	**6,827**	**5,131**	**8,756**	**9,310**	10,474	10,263	8,993	6,740

(1) Based on the number of Trust Units issued and outstanding at each record date.

(2) The fourth quarters include additional distributions declared relating to excess income earned during the full year ($0.06 per Trust Unit in 2009 and $0.35 per Trust Unit in 2008).

(3) See Non-GAAP Measures.

(4) The difference between Edmonton Par and Western Canada Select/Hardisty crude oil streams.

Revenue and Other Income

Revenues in 2009 were significantly lower than in 2008, due to lower realized prices and, to a lesser extent, lower production volumes. In December 2009, a judgement in the amount of $2.1 million in Freehold's favour was received and recorded in other income. The claim was based on Freehold's assertion of incorrect royalty payments and production from a terminated lease. Cash payment in full was received subsequent to year-end.

Net Revenue

($000s)	**2009**	2008	2007
Gross revenue	**119,965**	204,116	152,184
Royalty and mineral tax expense [1]	**(2,733)**	(6,616)	(6,263)
Net revenue	**117,232**	197,500	145,921
Other income	**2,122**	-	-

(1) Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.

The accompanying table demonstrates the net effect of price and volume variances on gross revenue.

Gross Revenue Variances

($000s)	**2009 vs. 2008**	2008 vs. 2007	2007 vs. 2006
Oil and NGL			
Production increase (decrease)	**(4,477)**	(13,510)	2,872
Price increase (decrease)	**(46,976)**	55,199	7,776
Net increase (decrease)	**(51,453)**	41,689	10,648
Natural gas			
Production decrease	**(2,450)**	(3,738)	(1,028)
Price increase (decrease)	**(28,559)**	11,473	(486)
Net increase (decrease)	**(31,009)**	7,735	(1,514)
Other revenue increase (decrease) [1]	**(1,689)**	2,508	(17)
Gross revenue increase (decrease)	**(84,151)**	51,932	9,117

(1) Other revenue includes potash, sulphur, lease rentals, processing fees, and interest income; excludes other income.

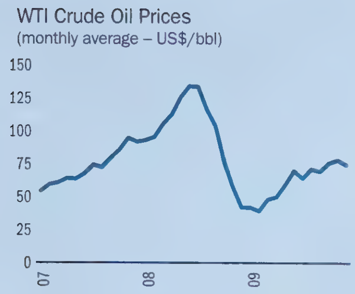
Production

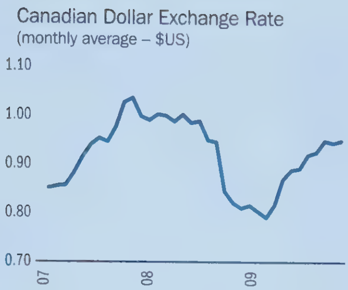
We have no operational control over our royalty lands. As we hold primarily small royalty interests in over 26,000 wells, obtaining timely production data from the well operators is extremely difficult. Thus, we use government reporting databases and past production receipts to estimate revenue accruals.

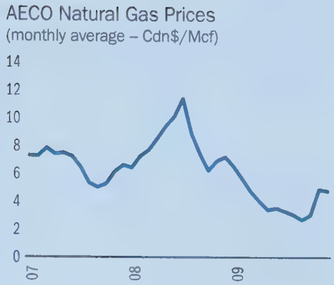
On a boe basis, our production was down 6% for the year, as drilling activity and acquisitions during 2009 were insufficient to offset natural production declines on our royalty lands. The deferral of our major capital projects to the second half of the year also contributed to the decline in working interest production. Royalty interests contributed 70% of total volumes produced in 2009. Our production mix for the year was approximately 36% natural gas and 64% liquids (33% heavy oil, 27% light and medium oil, and 4% NGL).

Production Summary

(boe/d)	**2009**	2008	2007
Royalty interest	**5,147**	5,546	5,825
Working interest	**2,155**	2,258	2,659
Total	**7,302**	7,804	8,484







Average Daily Production by Product Type

	2009	2008	2007
Light and medium oil (bbls/d)	**1,999**	2,035	1,925
Heavy oil (bbls/d)	**2,377**	2,533	3,109
NGL (bbls/d)	**323**	337	333
Total oil and NGL (bbls/d)	**4,699**	4,905	5,367
Natural gas (Mcf/d)	**15,615**	17,399	18,703
Oil equivalent (boe/d)	**7,302**	7,804	8,484
Total annual production (Mboe)	**2,665**	2,856	3,097
Potash (tonnes/d)	**5.1**	11.9	14.2

Production Reconciliation

(boe/d)	Royalty Interest	Working Interest	**Total Trust**
2008 average daily production rate	5,546	2,258	**7,804**
2008 activities, full year impact	450	170	**620**
2009 development	230	230	**460**
2009 acquisitions	5	-	**5**
Natural decline	(1,084)	(503)	**(1,587)**
2009 average daily production rate	5,147	2,155	**7,302**

Product Prices

The following table is a summary of average benchmark prices. Western Canada Select/Hardisty (WCS) is made up of existing Canadian heavy conventional and bitumen crude oils blended with sweet synthetic and condensate diluents. With an average API gravity of 20.5 degrees, the benchmark WCS heavy oil stream is considered a rough proxy for our average oil price realizations.

Average Benchmark Prices (1)

	2009	2008	2007
WTI crude oil (US$/bbl)	**61.81**	99.64	72.31
Exchange rate (US$/Cdn$)	**0.8798**	0.9428	0.9352
Edmonton Par crude oil (Cdn$/bbl)	**65.90**	102.16	76.35
Western Canada Select/Hardisty (Cdn$/bbl)	**58.66**	82.90	52.84
Light/heavy oil differential (Cdn$/bbl)	**7.24**	19.26	23.51
AECO natural gas (Cdn$/Mcf)	**4.13**	8.13	6.61

(1) Source for commodity prices: Canadian Association of Petroleum Producers.

Our average selling prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average price realizations were 37% lower in 2009 because of lower average commodity prices. Due to extremely low natural gas prices in 2009, processing fees, which are netted from the royalty payments, made up a larger proportion of price, further reducing our natural gas price realizations.

Average Selling Prices

	2009	2008	2007
Oil ($/bbl)	**57.24**	83.45	54.38
NGL ($/bbl)	**41.93**	67.60	53.53
Oil and NGL ($/bbl)	**56.19**	82.36	54.33
Natural gas ($/Mcf)	**3.67**	8.15	6.47
Oil equivalent ($/boe)	**44.00**	69.93	48.63
Potash ($/tonne)	**832.36**	613.33	225.28

Marketing and Hedging

Our production was unhedged in 2009, and we have no plans to enter into any foreign currency or commodity price hedges at this time. This policy is subject to quarterly review by our Board.

Royalty Production

Our royalty lands consist of a large number of properties with generally small volumes per property. A provision of most leases calls for our natural gas to be marketed with the lessees' production. Historically, we have chosen to market our oil production in the same manner. Some of our leases allow us to take our oil production in-kind. As at December 31, 2009, we were marketing approximately 42% of our royalty oil production using 30-day contracts.

Working Interest Production

We market most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing. Approximately 20% of our working interest natural gas production is sold under marketing arrangements tied to the Alberta monthly or daily spot price (AECO) or other indexed referenced prices. The balance of our working interest natural gas production (80%) is marketed with the operators' production.

Expenses

Royalty Expense and Mineral Tax

Oil and gas producers pay royalties to the owners of mineral rights from whom they have acquired leases. These are paid to the Crown (provincial and federal governments) and freehold mineral title owners. Crown royalty rates are tied to commodity prices and the level of oil and gas sales. Crown royalty rates were significantly lower in 2009 due to lower commodity prices and, to a lesser extent, lower production compared with last year.

We do not incur royalty expense on production from our royalty interest lands. As the royalty owner, we receive the royalty as income from other companies. Mineral tax is payable annually to the Crown. Mineral tax on our royalty lands in 2009 includes $1.3 million of freehold mineral tax recovered from certain lessees. Royalty expense in 2007 included approximately $250,000 in mineral tax that related to 2006.

Royalty Expense and Mineral Tax [1]

($000s, except as noted)	2009	2008	2007
Working interest			
Crown royalties	**2,018**	4,488	4,258
Third party royalties [2]	**875**	1,145	745
Mineral tax	**489**	445	252
Working interest	**3,382**	6,078	5,255
Per boe ($)	**4.30**	7.36	5.41
Royalty interest			
Crown royalties	**-**	-	-
Third party royalties [2]	**-**	-	-
Mineral tax	**(649)**	538	1,008
Royalty interest	**(649)**	538	1,008
Per boe ($)	**(0.35)**	0.27	0.47
Total Trust	**2,733**	6,616	6,263
Per boe ($)	**1.03**	2.32	2.02
As a percentage of gross revenue	**2%**	3%	4%

(1) Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.

(2) Third party royalties include mineral title and gross overriding royalty payments to parties other than the Crown.

Operating Expenses

Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas, and NGL production. Overhead recoveries associated with operated properties are excluded from operating costs and accounted for as a reduction to general and administrative (G&A) expenses. A percentage of operating costs is fixed and, as such, per boe operating costs are highly variable to production volumes. Included in operating expenses for 2009 was a one-time adjustment of approximately $800,000 ($1.01 per boe) for expenses incurred on certain working interest properties from 2005 to 2008 ($0.30 per boe on a total Trust basis).

Operating Expenses

($000s, except as noted)	2009	2008	2007
Working interest	**11,655**	11,299	11,076
Per boe ($)	**14.82**	13.67	11.41
Royalty interest [1]	**-**	-	-
Per boe ($)	**-**	-	-
Total operating expenses	**11,655**	11,299	11,076
Per boe ($)	**4.37**	3.96	3.58
As a percentage of gross revenue	**10%**	6%	7%

(1) We do not incur operating expenses with respect to royalty interests.

General and Administrative Expenses

G&A expenses include direct costs incurred by the Trust and reimbursement of the G&A expenses incurred by the Manager on behalf of the Trust (see Related Party Transactions). We have significant land administration, accounting and auditing requirements to administer and collect royalty payments, including systems to track development activity on the royalty lands. In 2009, we incurred higher office rent, directors' fees, salaries, and software fees, as well as expenses related to our IFRS conversion project.

General and Administrative Expenses

($000s, except as noted)	**2009**	2008	2007
Gross general and administrative expenses	**7,303**	6,877	5,933
Less overhead recoveries [1]	**(69)**	(87)	(79)
Net general and administrative expenses	**7,234**	6,790	5,854
Per boe ($)	**2.71**	2.38	1.89
As a percentage of gross revenue	**6%**	3%	4%

(1) Our overhead recoveries are minimal because we do not operate any of our royalty production.

Unit Based and Other Compensation

Manager's Long-Term Incentive Plan (LTIP)

The Trust is responsible for funding a portion of the long-term incentive compensation plan for employees of the Manager (the Manager's LTIP). After a three-year vesting period, participants receive cash compensation in relation to the value of a specified number of notional units. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. The LTIP liability is estimated at the end of each quarter based on the quarter-end Trust Unit price and performance factors; the related compensation charges are recognized over the vesting period. The 2006 LTIP grants vested in 2009 and $81,000 of unit based compensation was paid out. A current liability of $1.5 million at December 31, 2009 relates to the 2007 LTIP grants, which vested and were paid out in February 2010.

Deferred Trust Unit Plan

Fully-vested deferred trust units are granted annually to non-management directors and are redeemable for an equal number of Trust Units (less tax withholdings) any time after the director's retirement. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution (see Unitholders' Capital).

Retirement Benefit Plan

In 2009, the Trust agreed to participate in its proportionate share of a retirement benefit for certain employees of the Manager. The retirement benefit is payable in four equal instalments upon retirement after reaching the age of 65. Service costs are amortized on a straight-line basis over the expected average remaining service lifetime.

Unit Based and Other Compensation

($000s, except as noted)	**2009**	2008	2007
Manager's LTIP	**2,862**	(203)	366
Deferred trust unit plan	**352**	300	265
Retirement benefit	**504**	-	-
Unit based and other compensation	**3,718**	97	631
Per boe ($)	**1.40**	0.03	0.20
As a percentage of gross revenue	**3.1%**	0.0%	0.4%

Interest Expenses

Interest and financing expense declined 34% in 2009 due to a reduction in lending rates, partly offset by higher rollover fees related to the annual renewal of our credit facilities in May 2009. The average effective interest rate on advances under our credit facilities in 2009 was 2.4% (2008 – 4.3%).

Interest and Financing

($000s, except as noted)	**2009**	2008	2007
Interest on operating line or other	**-**	31	3
Interest on long-term debt	**4,678**	7,008	7,002
Interest and financing	**4,678**	7,039	7,005
Per boe ($)	**1.76**	2.46	2.26
As a percentage of gross revenue	**4%**	3%	5%

Depletion, Depreciation and Accretion of Asset Retirement Obligation

Oil and gas properties and royalty interests, including the cost of production equipment, future capital costs associated with proved reserves, and the capitalized portion of asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties payable (see Accounting Policies and Critical Estimates). Reserves are independently evaluated every year as at December 31. For the first three quarters of 2009, the estimate of proved reserves was based on the independent evaluation dated December 31, 2008, adjusted for acquisitions and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as at December 31, 2009.

Our ceiling test calculation, performed at December 31, 2009, resulted in no impairment loss. The future prices used in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for our quality, transportation, and contract differences.

Depletion, Depreciation and Accretion Expenses

($000s, except as noted)	**2009**	2008	2007
Depletion and depreciation	**63,060**	67,948	72,400
Accretion of asset retirement obligation	**333**	384	266
Total depletion, depreciation and accretion expenses	**63,393**	68,332	72,666
Per boe ($)	**23.79**	23.92	23.47
As a percentage of gross revenue	**53%**	33%	48%

Reclamation Fund

We are liable for our share of ongoing environmental obligations and the ultimate reclamation of our working interest properties upon abandonment. We have no reclamation responsibilities on our royalty assets, as these are the responsibility of the working interest owners. Ongoing environmental obligations are funded from funds generated from operations. At December 31, 2009, our estimated undiscounted share of future environmental and reclamation obligations for the working interest properties was approximately $25.6 million.

In 1996, we established a reclamation fund to ensure that required funds are available for future reclamation of working interest wells and facilities once they have reached the end of their economic lives. The fund consists of cash, invested in an interest-bearing account, and is funded by quarterly cash payments. We contributed $607,000 in cash and interest to the fund during 2009 and withdrew $173,000, which was spent on reclamation activities. At December 31, 2009, the fund had a balance of $2.3 million. For 2010, quarterly contributions will be $200,000 to ensure that future obligations can be met.

Reclamation Fund Summary

($000s)	Cumulative Since Inception	**2009**	2008	2007
Reclamation fund, beginning balance	-	**1,827**	1,788	2,117
Reclamation fund contributions	4,700	**607**	641	470
Expenditures on reclamation	(2,439)	**(173)**	(602)	(799)
Reclamation fund, ending balance	2,261	**2,261**	1,827	1,788

Management Fees

The Manager of the Trust receives a management fee in Trust Units. The issue of 7.9 million Trust Units from treasury in the fourth quarter of 2009 resulted in a pro-rata increase in the management fee, in accordance with the management agreement (see Unitholders' Capital).

Management Fees (paid in Trust Units)

	2009	2008	2007
Trust Units issued in payment of management fees	**148,597**	142,616	142,616
Ascribed value ($000s) (1)	**2,018**	2,482	2,130
Per boe ($)	**0.76**	0.87	0.69
As a percentage of gross revenue	**2%**	1%	1%
As a percentage of distributions	**3%**	2%	2%

(1) The ascribed value of the management fees is based on the closing Trust Unit price at the end of each quarter.

Taxes

Income and Capital Taxes

Freehold Royalty Trust is a taxable trust under the *Income Tax Act* (Canada). We distribute substantially all of our taxable income to Unitholders. By doing so, exposure to current tax at the trust level is eliminated.

Capital taxes consist primarily of the Saskatchewan Capital Tax applied to both taxable capital and gross revenues in that province. Our subsidiary, Freehold Resources Ltd., is a Canadian corporation subject to tax in various jurisdictions. Freehold Resources Ltd. can deduct royalty payments to the Trust in determining its taxable income, and is generally liable for income taxes on its 1% residual interest. Freehold Resources Ltd. is subject to federal and capital tax in any jurisdiction (federal and provincial) in which it has a permanent establishment.

Income and Capital Taxes

($000s)	**2009**	2008	2007
Provincial capital tax	**255**	398	179
Current income tax	**-**	-	-
Total	**255**	398	179

Tax Pools

We are entitled to claim certain tax deductions available to all owners of oil and gas properties. By using two principal deductions – the Canadian Oil and Gas Property Expense and the Resource Allowance – cash distributions in the Trust's initial years were sheltered from income tax. Over time, because of a general reduction in tax pools available for future claims, an increasing percentage of the annual distributions became taxable. On a consolidated basis the Trust's carrying value for book purposes exceeded the amount available for tax purposes by $176 million at December 31, 2009.

Tax Pools [1]

($000s)	2009	2008	2007
Canadian oil and gas property tax expense	**179,058**	188,957	202,164
Canadian development expense	**19,357**	16,154	13,507
Canadian exploration expense	**547**	276	131
Capital cost allowance	**11,507**	10,887	10,708
Unit issue costs	**3,950**	2,214	4,427
Total	**214,419**	218,488	230,937

(1) These amounts, subject to review by Canada Revenue Agency, represent Freehold Royalty Trust's direct tax pools as well as the tax pools of our subsidiary, Freehold Resources Ltd.

Future Income Taxes

The implementation of tax on distributions from certain publicly-traded specified investment flow-through (SIFT) entities will result in certain of our distributions that would have otherwise been taxed as ordinary income being characterized as dividends in addition to being subject to tax at corporate rates at Freehold's level. Any resultant trust level taxable income will be taxed at a rate that will be approximately equal to corporate income tax rates. The combined federal and provincial (Alberta) SIFT tax rate is expected to be 26.5% in 2011, and 25.0% thereafter. There were few tax pools associated with our assets when the Trust was created in 1996 because our property base consisted primarily of royalties. At year-end 2009, we had approximately $214.4 million of available tax pools. In 2011, with our current tax pools, our distributions will be taxable at the entity level under the new rules.

The future income tax liability on our Consolidated Balance Sheets as at December 31, 2009, represents the net difference between tax values and accounting values (referred to as temporary differences) effected at substantively enacted tax rates expected to apply when the differences reverse. The SIFT tax is not expected to apply to Freehold until 2011 as a transition period applies to trusts that existed prior to November 1, 2006. However, under Canadian GAAP, the enactment of the SIFT tax legislation requires the recognition of future income tax.

Liquidity and Capital Resources

We define capital as long-term debt, Unitholders' equity, and working capital. We manage our capital structure taking into account operating activities, debt levels, debt covenants, capital expenditures, reclamation fund obligations, and distribution levels. We also consider changes in economic conditions and commodity prices as well as the risk characteristics of our assets. We have a depleting asset base, and ongoing development activities and acquisitions are necessary to replace production and extend reserve life. From time to time, we may issue Trust Units or adjust capital spending to manage current and projected debt levels.

Operating Activities

The following table reconciles funds generated from operations to its nearest measure prescribed by GAAP.

Operating Activities

($000s, except as noted)	2009	2008	2007
Cash provided by operating activities	**95,659**	179,252	119,641
Increase (decrease) in non-cash working capital	**(574)**	(7,970)	1,367
Funds generated from operations	**95,085**	171,282	121,008
Per Trust Unit ($)	**1.90**	3.47	2.46

Financing Activities

We have a $195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks and a $15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 250 to 400 basis points, and standby fees. The facilities are secured with $300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants.

At December 31, 2009, we had $165 million of available capacity under our credit facilities. Net proceeds from our equity issue in December were used, initially, to reduce long-term debt. On December 21, 2009, we drew on our credit facilities to fund a $10 million royalty acquisition. Subsequent to year-end, we drew on our credit facilities to fund a $39 million royalty acquisition.

By comparison, at December 31, 2008, we had $70 million of available capacity under our credit facilities, but some of this capacity was used to pay December's distribution paid on January 15, 2009. The effect of December's distribution payable was shown in a working capital deficiency of $20.1 million and net debt of $160.1 million at December 31, 2008.

Debt Analysis

($000s)	**2009**	2008	2007
Long-term debt	**45,000**	140,000	178,000
Short-term debt (operating line)	**-**	-	-
Total debt	**45,000**	140,000	178,000
Less: working capital	**(3,082)**	(20,055)	11,219
Net debt obligations	**48,082**	160,055	166,781

We are bound by covenants on our credit facilities and we monitor these monthly to ensure compliance. Under our credit facility, we are restricted from making distributions if we are or would be in default under the credit facility or if our borrowings thereunder exceed our borrowing base, currently set at $210 million. As at December 31, 2009, the Trust was in compliance with all such covenants.

Financial Leverage and Coverage Ratios

	2009	2008	2007
Net debt to trailing funds generated from operations (times)	**0.5**	0.9	1.4
Net debt to distributions (times)	**0.7**	1.1	1.8
Distributions to interest expense (times)	**15.1**	20.4	13.5
Net debt to net debt plus equity (%)	**14**	42	40

We retain working capital primarily to fund capital expenditures or acquisitions and reduce bank indebtedness. The following table shows the changes in working capital during the past four quarters. In the oil and gas industry, accounts receivable from industry partners are typically settled in the following month. However, due to administrative issues, payments to royalty owners are often delayed longer. Therefore, working capital can fluctuate significantly due to volume and price changes at each period end. At the end of 2009, we had a working capital deficiency of $3.1 million and higher accounts receivable, attributable to higher oil prices and other income. At year-end 2008, current liabilities included the December distribution of $0.60 per Trust Unit (of which $0.35 related to additional income earned in 2008) that was paid on January 15, 2009.

Components of Working Capital

($000s)	**Dec. 31 2009**	Sept. 30 2009	June 30 2009	Mar. 31 2009	Dec. 31 2008
Cash	**432**	311	369	546	537
Current portion of deferred compensation	**-**	-	-	34	-
Accounts receivable	**24,056**	19,622	21,315	21,870	23,261
Current assets	**24,488**	19,933	21,684	22,450	23,798
Distributions declared	**(8,050)**	(5,950)	(4,953)	(4,950)	(29,676)
Current portion of unit based and other compensation	**(1,643)**	(1,559)	(743)	(131)	(83)
Accounts payable and accrued liabilities	**(17,877)**	(20,243)	(13,824)	(15,780)	(14,094)
Current liabilities	**(27,570)**	(27,752)	(19,520)	(20,861)	(43,853)
Working capital [1]	**(3,082)**	(7,819)	2,164	1,589	(20,055)

(1) Working capital is comprised of current assets minus current liabilities.

Commitments

Our borrowing base is dependent on our lenders' annual review and interpretation of our reserves and future commodity prices. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice. If our lenders decide not to extend our credit facilities, we have a contractual obligation to make principal repayments on our long-term debt. Equal quarterly payments would be required in 2011 and 2012 based on the principal outstanding at the time the current agreement expires, which is May 2010. As per the terms of the agreement, the first quarterly payment would commence on January 1, 2011.

Unitholders' Capital

On October 26, 2009, our Board approved the monthly issuance of Trust Units from treasury for the DRIP. Previously, Trust Units issued in relation to the DRIP were purchased through the facilities of the Toronto Stock Exchange at prevailing market prices. In 2009, Freehold issued 260,740 Trust Units related to the DRIP. The ascribed value of $3.9 million was based on the weighted average closing price for the 10 trading days preceding each distribution date.

CN Pension Trust Funds, which owns approximately 23% of our Trust Units, began participating in the DRIP, effective with the distribution paid on November 15, 2009. With a higher participation rate in the DRIP and by issuing Trust Units from treasury instead of purchasing them in the market, we have a new source of capital, which can be used to develop our working interest properties, reduce long-term debt, or fund acquisitions.

On December 10, 2009, Freehold closed an equity offering and issued 7,618,750 Trust Units at $15.15 per Trust Unit for gross proceeds of $115.4 million. The issue costs, including underwriter's fees, were $4.9 million resulting in net proceeds of $110.5 million.

As at December 31, 2009, there were 53,070 deferred trust units (DTUs) outstanding and as at March 3, 2010, there were 68,083 DTUs outstanding. During 2009, 22,577 DTUs were granted and 22,038 DTUs were redeemed.

As at December 31, 2009, there were 57,502,943 Trust Units outstanding and as at March 3, 2010, there were 57,761,762 Trust Units outstanding. Our Trust Indenture provides that not more than 49% of the Trust's Units can be held by non-residents of Canada. We monitor foreign ownership levels regularly through declarations from Unitholders and geographical searches. Accordingly, the reported level of Canadian ownership is subject to these limitations, and the level of Canadian ownership can change at any time without notice.

Trust Units Outstanding

	2009	2008	2007
Weighted average			
Basic	**49,999,617**	49,370,878	49,228,411
Diluted	**50,053,435**	49,412,670	49,228,411
At December 31	**57,502,943**	49,459,429	49,316,813

Distribution Analysis

Distributions in 2009 totalled $70.5 million ($1.40 per Trust Unit). This included an additional distribution of $0.06 per Trust Unit (paid on December 15) as a result of excess cash from operating activities, which was distributed to Unitholders in order to eliminate direct taxation at the Trust level.

For Canadian tax purposes, 82% of distributions declared in 2009 were taxable as income, unless held in a registered plan. The remaining 18% of distributions were classified as a return of capital. Additional tax information is available on our website.

2009 Distributions Declared

Record Date	Payment Date	Distribution ($ per Trust Unit)
January 31, 2009	February 15, 2009	0.10
February 28, 2009	March 15, 2009	0.10
March 31, 2009	April 15, 2009	0.10
April 30, 2009	May 15, 2009	0.10
May 31, 2009	June 15, 2009	0.10
June 30, 2009	July 15, 2009	0.10
July 31, 2009	August 15, 2009	0.10
August 31, 2009	September 15, 2009	0.12
September 30, 2009	October 15, 2009	0.12
October 31, 2009	November 15, 2009	0.12
November 30, 2009	December 15, 2009	0.20 (1)
December 31, 2009	January 15, 2010	0.14
Total		**1.40**

(1) Includes an additional $0.06 representing additional income in 2009.

From inception to December 31, 2009, the Trust has distributed $794.9 million ($20.53 per Trust Unit) to Unitholders.

Accumulated Distributions

	2009	2008	2007
Distributions declared ($000s)			
Accumulated, beginning of year	**724,418**	580,669	486,124
Accumulated, end of year	**794,898**	724,418	580,669
Distributions per Trust Unit ($) (1)			
Accumulated, beginning of year	**19.13**	16.22	14.30
Accumulated, end of year	**20.53**	19.13	16.22

(1) Based on the number of Trust Units issued and outstanding at each record date.

The following table illustrates the relationship between cash provided from operating activities and historical distributions, as well as net income and historical distributions. The Trust has historically distributed less cash than cash provided by operating activities. This excess cash has been used to fund capital expenditures and acquisitions, and repay bank debt as required. Net income includes significant non-cash charges that do not affect cash flow. These charges amounted to $63.5 million in 2009 (2008 – $61.9 million). Net earnings also include fluctuations in future income taxes due to changes in tax rates and tax rules. In addition, depletion and depreciation on petroleum and natural gas interests are non-cash changes that do not represent the actual cost of maintaining our productive capacity given the natural depletion associated with oil and gas assets. In these instances, where distributions exceed net earnings, a portion of the cash distribution paid to Unitholders may represent an economic return of the Unitholders' capital.

Distribution Analysis

($000s, except as noted)	**2009**	2008	2007
Cash provided by operating activities	**95,659**	179,252	119,641
Net income (loss)	**31,741**	109,956	(1,192)
Distributions declared	**70,480**	143,749	94,545
Excess of cash provided by operating activities over distributions declared	**36%**	25%	27%
Shortfall of net income over distributions declared	**(55%)**	(24%)	(101%)

SIFT Tax Legislation

The new SIFT tax is expected to result in adverse tax consequences to Freehold and certain Unitholders (including Unitholders that are tax deferred or non-residents of Canada) and may impact our cash distributions starting in 2011. The after tax impact for Canadian resident individuals who hold Freehold Trust Units outside a tax-deferred plan is mitigated by the federal and provincial enhanced dividend tax credit mechanism that will apply in 2011 and future years.

The SIFT tax may reduce the value of our Trust Units, which would be expected to increase our cost of raising capital in the public capital markets. In addition, the tax changes are expected to substantially eliminate the competitive advantage that Freehold and other Canadian trusts enjoy relative to their corporate peers in raising capital in a tax-efficient manner and place Freehold and other Canadian trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation. The tax changes are also expected to make our Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for Freehold to compete effectively for acquisition opportunities. There can be no assurance that we will be able to reorganize Freehold's legal and tax structure to mitigate the expected impact of the tax changes.

Further, the tax changes provide that, while there is no intention to prevent "normal growth" during the transitional period, any "undue expansion" could result in the transition period being "revisited", presumably with the loss of the benefit to us of that transitional period. As a result, the adverse tax consequences resulting from the tax changes could be realized sooner than January 1, 2011.

On December 15, 2006, the Department of Finance issued guidelines with respect to what is meant by normal growth in this context. Normal growth would include equity growth within certain "safe harbour" limits, measured by reference to market capitalization as of the end of trading on October 31, 2006. On December 4, 2008, the federal government proposed revisions to these guidelines to accelerate the safe harbour amount, permitting a SIFT entity to immediately issue new equity to bring its cumulative growth up to 100% of its October 31, 2006 market capitalization. Our market capitalization as of the close of trading on October 31, 2006 was approximately $929 million. In 2009, we issued 8.0 million Trust Units from treasury with an ascribed value of $117 million, which is well within the safe harbour limit.

We do not anticipate that the normal growth guidelines will impair our ability to raise the capital required to maintain and grow our existing operations in the ordinary course during the transitional period. However, they could adversely affect the cost of raising capital and our ability to undertake significant acquisitions.

In 2008, our Board established a special committee of independent directors and charged them with a mandate to determine a course of action that best maximizes Unitholder value when the SIFT tax comes into effect. While a final determination has not yet been made, the committee has been examining the structures that our peers are adopting, assessing overall market sentiment including future access to capital, and considering complex legal and tax issues. We anticipate the special committee's recommendation before the end of 2010.

On March 12, 2009, the federal government enacted legislation containing detailed rules providing for the conversion of SIFT entities into corporations. These rules enable the conversion of a SIFT entity to a corporation without undue tax consequences for the SIFT entity or its investors, and facilitates such conversion with minimal filing requirements. The opportunity for a SIFT entity to convert to a corporation on a tax-free basis pursuant to the SIFT conversion rules is only available until the end of 2012.

Investing Activities

Acquisitions

Our strategy is to acquire appropriate assets, with a bias toward royalty interests, to provide long-term growth in the value of the Trust. Our acquisition criteria include the following factors:

- quality assets – producing properties with an established production history and low reserve risk;
- attractive returns – a forecast internal rate of return that is 400 basis points above long-term (ten year) Government of Canada bonds;
- reasonable assumptions – commodity price and exchange rate assumptions from an independent engineering firm acceptable to the Board;
- high operating netbacks; and
- long economic life – an expected economic life of not less than ten years.

We continue to pursue opportunities to augment our production and reserves, primarily targeting royalty interests. We maintain a disciplined valuation approach to ensure that any acquisition we complete will be accretive to our present and future Unitholders. Over the past three years, we have completed the following acquisitions:

- Subsequent to year-end, on February 17, 2010, we acquired royalty interests in Alberta, Saskatchewan, and British Columbia, for $39 million.
- On December 21, 2009, we acquired royalty interests in Alberta for $10 million.
- On July 7, 2008, we acquired royalty and minor working interests in Alberta for $8.5 million.
- On August 31, 2007, we acquired royalty interests in Alberta and Saskatchewan for $57.6 million.
- On September 5, 2007, we acquired royalty interests in Alberta for $32.8 million.

These acquisitions were all funded through our credit facilities.

Property and Royalty Acquisitions

($000s)	**2009**	2008	2007
Purchase price	**10,700**	8,475	93,700
Interest expense	**112**	-	1,745
Evaluation and legal costs	**47**	-	405
Purchase price adjustments [1]	**(849)**	-	(5,394)
Prior years acquisition adjustments	**(471)**	(782)	-
Additions to petroleum and natural gas interests	**9,539**	7,693	90,456

(1) Net revenue from effective date to closing.

Capital Expenditures

Our capital expenditure obligations (with respect to our working interest properties) are deducted from funds generated from operations prior to the determination of distributions to Unitholders. As we do not incur development expenditures on our royalty lands, our capital requirements are modest, relative to most energy trusts. In 2009, development expenditures of $15.5 million amounted to 16.3% of funds generated from operations.

We expect to fund distributions and capital expenditures from cash provided by operating activities. However, we will continue to fund acquisitions and growth through additional debt and equity. In the oil and gas sector, because of the nature of reserve reporting, natural reservoir depletion, and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Therefore, maintenance capital is not disclosed separately from development capital spending.

Capital Expenditures

($000s, except as noted)	**2009**	2008	2007
Development drilling	**11,702**	10,349	8,526
Plant and facilities	**3,789**	2,643	3,641
Total capital expenditures	**15,491**	12,992	12,167
As a percentage of funds generated from operations	**16.3%**	7.6%	10.1%

Business Risks and Mitigating Strategies

The operations of an energy trust are subject to the same industry risks and conditions faced by conventional oil and gas companies. The most significant of these include:

- fluctuations in commodity prices and quality differentials as a result of weather patterns, world and North American market forces or shifts in the balance between supply and demand for crude oil and natural gas;
- variations in currency exchange rates;
- imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves. Our reserves will deplete over time through continued production and we and our industry partners and royalty payors may not be able to replace these reserves on an economic basis;
- industry activity levels and intense competition for land, goods and services, and qualified personnel;
- stock market volatility and the ability to access sufficient capital from internal and external sources;
- risk associated with volatility in global financial markets;
- risk associated with the renegotiation of our credit facility;
- operational or marketing risks resulting in delivery interruptions, delays or unanticipated production declines;
- changes in government regulations, taxation, and royalties; and
- safety and environmental risks.

As a royalty trust, we are also subject to the following risks:

- Fifteen royalty payors account for about two-thirds of our royalty income, and changes to their businesses may have a significant effect on our results.
- Higher prime borrowing rates may increase interest expense on our debt and may make fixed income investments more attractive to investors of Trust Units.

For a more detailed description of risk factors, please see our AIF.

We employ the following strategies to mitigate these risks:

- Our diversified revenue stream limits the size of any one property with respect to our total assets.
- We are not liable for abandonment and reclamation costs on our royalty lands.
- Due to our high percentage of royalty lands, we have one of the lowest all-in cost structures of our peer group. In addition, we maintain a focus on controlling direct costs to maximize profitability.
- We maintain an aggressive auditing program to collect royalties on production from our lands in accordance with the terms of the various leases and royalty agreements. During 2009, our audit staff issued audit exception queries amounting to $5.6 million, bringing the total amount of audit exception queries since 1997 to $38.1 million, of which we have successfully recovered $27.1 million.
- We adhere to strict investment criteria for acquisitions, seeking royalty and working interest properties that have high netbacks, long reserve life, low risk development potential, and product diversification.
- We market our products to a diverse range of buyers. Currently, we do not have any commodity price, exchange rate, or interest rate hedging programs in place.
- We employ a qualified team of oil and gas professionals with many years of experience and knowledge in managing our assets.
- We maintain levels of liability insurance that meet or exceed industry standards.
- We employ a conservative approach to debt management. As circumstances warrant, we allocate a portion of funds generated from operations to debt repayment.

Environmental Regulation and Risk

The oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In 2002, the Government of Canada ratified the Kyoto Protocol, which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate about Canada's ability to meet these targets and the government's strategy or alternative strategies on climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases, whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on oil and natural gas operations, including those of the Trust.

On April 26, 2007, the federal government released its *Action Plan to Reduce Greenhouse Gases and Air Pollution*, also known as *ecoAction*, which includes the regulatory framework for air emissions. The plan covers not only large industry, but also regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products. Regarding large industry and industry related projects, *ecoAction* is intended to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) a 50% reduction in air pollution from industry by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. To facilitate compliance with the plan's requirements, while at the same time allowing companies to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) inhouse reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark, in December 2009, to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen

Accord reinforces the commitment to reducing greenhouse gas emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding greenhouse gas emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016. In response to the Copenhagen Accord, the federal government has recently indicated that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020.

On January 24, 2008, the Alberta government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan encompasses three areas:

- carbon capture and storage, which will be mandatory for in situ oil sand facilities that use heavy fuels for steam generation;
- energy conservation and efficiency; and
- greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage.

In addition to this action plan, the Provincial Energy Strategy, unveiled on December 11, 2008, is expected to support the upgrading, refining and petrochemical clusters existing in the province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on our operations and financial condition.

Controls and Accounting Matters

In compliance with National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings* (NI 52-109), Freehold has filed certificates signed by our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) that, among other things, deal with the matter of disclosure controls and procedures and internal control over financial reporting. While we believe that our disclosure controls and procedures provide a reasonable level of assurance that they are effective, we do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

Disclosure Controls

Disclosure controls and procedures are controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed in regulatory filings is recorded, processed, summarized, and reported within the periods specified. They include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

Management has evaluated the effectiveness of the Trust's disclosure controls and procedures as of March 3, 2010. This evaluation was performed under the supervision of, and with the participation of the CEO and the CFO. It took into consideration Freehold's Disclosure, Insider Trading, Code of Business Conduct and Conflict of Interest, and Whistleblower policies, as well as the functioning of the Manager, the officers, the Board and Board Committees. In addition, the evaluation covered the processes, systems and capabilities relating to regulatory filings, public disclosures, and the identification and communication of material information. Based on this evaluation, management has concluded that Freehold's disclosure controls are effective in ensuring that material information relating to the Trust is made known to management on a timely basis.

Internal Control Over Financial Reporting

Internal control over financial reporting is a process designed to provide reasonable assurance about the reliability of financial reporting and the preparation of financial statements in accordance with Canadian GAAP. The process includes policies and procedures to:

- maintain records that accurately and fairly reflect transactions and dispositions of assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements and that receipts and expenditures are being made with proper authorization; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized transactions that could have a material effect on the financial statements.

The CEO and CFO of the Trust are responsible for establishing and maintaining internal control over financial reporting (ICFR). They have caused ICFR to be designed under their supervision to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with Canadian GAAP. The control framework used to design ICFR is the *Internal Control – Integrated Framework* (COSO Framework) published by The Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Under the supervision of the CEO and CFO, the Trust conducted an evaluation of the effectiveness of its ICFR as at December 31, 2009, as structured within the COSO Framework. Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2009, the Trust's ICFR provides reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. There were no changes in the Trust's ICFR during 2009 that materially affected the Trust's ICFR.

Changes in Accounting Policies, Including Initial Adoption, and New Accounting Standards

International Financial Reporting Standards (IFRS)

In January 2006, the Canadian Accounting Standards Board (AcSB) adopted a strategic plan for the direction of accounting standards in Canada. As part of the AcSB's strategic plan, Canadian publicly accountable entities will be required to report under International Financial Reporting Standards (IFRS), which will replace Canadian GAAP. In October 2009, the AcSB confirmed January 1, 2011 as the changeover date to commence reporting under IFRS. This adoption date will require the restatement, for comparative purposes, of amounts reported by Freehold for the year ended December 31, 2010, including our opening balance sheet as at January 1, 2010.

In preparation for the transition from current Canadian GAAP to IFRS, we have assigned internal staff to lead the conversion project, retained an external advisor to assist us and continue to involve our auditors in the process. Our transition plan addresses resources required, employee training, analysis of accounting standard differences, accounting policy determination, evaluation of information system requirements and an impact assessment on operations, internal controls over financial reporting and disclosures.

We are currently analyzing the accounting policy choices available under IFRS and assessing the impact of certain accounting standards. Our business impact study has identified areas of high and medium impact on the Trust. IFRS 1, *First-Time Adoption of International Financial Reporting Standards* provides entities with a number of exemptions to avoid full retroactive application. Some of the major accounting policy considerations are identified below; however, more may emerge as the project continues.

- For property, plant and equipment, we have decisions to make under IAS 16 regarding asset valuation, cash generating units, and depletion and depreciation. Under IFRS 1, we have an option to record opening values at their deemed cost, which is the net book value under Canadian GAAP at January 1, 2010, rather than retrospectively applying the requirements of IAS 16.
- We need to determine if Freehold has any exploration and evaluation assets and whether these assets need to be broken down into cash generating units. A policy will have to be formulated as to when these assets will be transferred to being treated under IAS 16 rather than IFRS 6. The original valuation of these assets can be affected by IFRS 1 where there is an option to use their deemed cost which is the net book value under Canadian GAAP at January 1, 2010.
- Impairment testing for Freehold's property, plant and equipment and, exploration and evaluation assets will have to occur at a cash generating unit. Impairment is tested at reporting dates if there is an indication that an asset may be impaired. Impairments may be reversed if the impairment indicators have reversed.

- For our asset retirement obligations, we have an option under IFRS 1 to revalue our obligation at January 1, 2010, using the appropriate discount rate at this date, rather than retrospectively revaluing each year as required under IAS 37.
- For share-based payments, we have an option not to apply IFRS 2 retrospectively if, by January 1, 2010, equity settled instruments were fully vested or cash settled payments were transacted.
- There are considerations to be made as to the treatment of Trust Units under IAS 32.

We will continue to monitor all business agreements, including lending agreements, to ensure that they remain unaffected by the changeover to IFRS. Information technology systems are being evaluated and appear to be adequate with minor modifications. Internal controls over financial reporting will be assessed as accounting policy choices are finalized to ensure that additional controls and procedures are in place for future reporting requirements. Disclosure controls and procedures will also be evaluated to ensure that we keep stakeholders' informed about the transition. We plan to make final decisions on accounting policies, information technology requirements and training requirements by the third quarter 2010, while internal controls and disclosures issues will not be finalized until early in 2011. We will provide progress updates on our IFRS conversion project in our quarterly MD&A.

Financial Instruments – Disclosures

In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862, *Financial Instruments – Disclosures*, to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Trust on December 31, 2009.

Accounting Policies and Critical Estimates

Our financial statements are prepared within a framework of Canadian GAAP selected by management and approved by our Board. The assets, liabilities, revenues, and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and natural gas reserve estimation, depletion, impairment of assets, oil and gas revenue accruals, asset retirement obligations, and future income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

An estimate is considered a critical accounting estimate if it requires management to make assumptions about matters that are highly uncertain, and if different estimates that could have been used would have a material impact. We continually evaluate the estimates and assumptions. In the normal course, changes are made to assumptions underlying all critical accounting estimates to reflect current economic conditions, and updating of historical information is used to develop the assumptions. Except as discussed in this MD&A, we are not aware of trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

Reserve Estimates, Depletion and Ceiling Test

The current estimates of oil and gas reserves and our future capital expenditures are based on an independent evaluation conducted as of December 31, 2009. Reserve estimates are updated once a year (as at December 31) and when a significant acquisition is completed. The reserve and recovery information provided are only estimates. The actual production and ultimate reserves may be greater than or less than the estimates and the differences may be material.

We follow the full cost method of accounting for petroleum and natural gas interests. Oil and gas properties and royalty interests, including the costs of production equipment and future capital costs associated with proved reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. An increase in estimated proved oil and gas reserves would result in a corresponding reduction in the depletion rate. As at December 31, 2009, the depletion calculation included $0.9 million for estimated future development costs associated with proved undeveloped reserves and excluded $27.6 million for the lower of cost and estimated value of unproved lands.

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties. The ceiling test estimates were reviewed at year-end to ensure that they are reasonable and supportable in light of current economic conditions. The ceiling test, performed as at December 31, 2009, indicated that the undiscounted future net revenues from proved reserves exceed the net book value of the properties. Accordingly, no write down of oil and gas properties was required.

Accruals

Freehold follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of revenues, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. We expect that these accrual estimates will be revised, upwards or downwards, based on the receipt of actual results. We have no operational control over our royalty lands, and we primarily hold small interests in several thousand wells. Thus, obtaining timely production data from the well operators is extremely difficult. As a result, we use government reporting databases and past production receipts to estimate revenue accruals.

Asset Retirement Obligation

Accounting standards require us to recognize the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on the unit-of-production method over the life of the reserves. Once the initial asset retirement obligation is measured, it must be adjusted at the end of each period to reflect the passage of time as well as changes in the estimated future cash flows that underlie the obligation.

We have no asset retirement obligations on our royalty income properties. Our asset retirement obligation results from the responsibility to abandon and reclaim our net share of all working interest properties. The net present value of our total asset retirement obligation is estimated to be $7.2 million (discounted at a weighted average credit adjusted risk free rate of 5.8%), with the undiscounted value being $25.6 million. Payments to settle the obligations are expected to occur continuously over the next 60 years, with the majority of obligations being more than 15 years away.

In determining our asset retirement obligation, we are required to make a significant number of estimates with respect to activities that will occur in many years to come. In arriving at the recorded amount of the asset retirement obligation, numerous assumptions are made with respect to ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligation also results in an increase to the carrying cost of capital assets. The obligation accretes to a higher amount with the passage of time as it is determined using discounted present values. A change in any one of the assumptions could affect the estimated future obligation and in return, net income. It is difficult to determine the impact of a change in any one of our assumptions. As a result, a reasonable sensitivity analysis cannot be performed.

Future Income Taxes

We follow the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of future income tax may be greater than or less than the estimates and the differences may be material.

Unit Based and Other Compensation
Effective January 1, 2006, we began funding a portion of the Manager's LTIP. The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. As participants in the Manager's LTIP receive a cash payment on a fixed vesting date, compensation expense is determined based on the intrinsic value of the rights at each period end. The valuation incorporates the period end Trust Unit price, the number of rights outstanding at each period end, and certain management assumptions. Compensation expense is recognized over the vesting period with a corresponding increase or decrease in liabilities. We have not incorporated an estimated forfeiture rate for rights that will not vest; rather, we account for actual forfeitures as they occur (see Unit Based and Other Compensation).

A deferred trust unit plan was established in 2006 for the non-management directors of Freehold whereby fully vested deferred trust units are granted annually. Under this plan, distributions to Unitholders declared prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. Compensation expense is recognized at market value at the time of grant or distribution with a corresponding increase to contributed surplus. Upon redemption of the deferred trust units for Trust Units, the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' capital (see Trust Units Outstanding and Unit Based and Other Compensation).

In 2009, we agreed to fund the Trust's proportionate share of a retirement benefit for certain employees of the Manager, upon fulfilling certain criteria. We accrue the Trust's share of the post retirement costs over the service life of the employees.

Related Party Transactions
The Manager receives a quarterly management fee paid in Trust Units, and recovers the portion of its general and administrative expenses allocated to the Trust and a similar portion of its long-term incentive plan and retirement benefit costs (see Unit Based and Other Compensation).

In 2009, Freehold issued 148,597 Trust Units (2008 – 142,616) as a management fee to the Manager pursuant to a management agreement. The ascribed value of $2.0 million (2008 – $2.5 million) is based on the closing price of the Trust Units on the last trading day of the quarter.

In 2009, the Manager charged the Trust $5.7 million in general and administrative costs (2008 – $5.3 million). At December 31, 2009, there was $0.4 million (2008 – $nil) in accounts payable and accrued liabilities relating to these costs. The transactions were in the normal course of operations and were measured at the exchange amount, which was the amount of consideration established and agreed to by the Trust and the Manager.

Contingencies
In May 2009, a statement of claim was filed against the Trust for $9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, the Trust has assessed the claim, believes it has no merit, and intends to aggressively defend itself in the claim. The claim's outcome is not determinable; therefore, no liability has been recorded in the financial statements.

In December 2009, a judgment of $2.1 million in Freehold's favour was received and recorded in other income. The claim was based on Freehold's assertion of incorrect royalty payments and production from a terminated lease. Cash payment in full was received subsequent to year-end. The defendant has appealed this judgment but Freehold and its legal counsel believe there are no grounds for a successful appeal. The appeal's outcome is not determinable; therefore, no liability has been recorded in the financial statements.

Forward-Looking Statements

Certain statements contained in this MD&A constitute forward-looking statements. These statements relate to future events or our expectations of future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "forecast", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions (including the negatives thereof). These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and, as such, forward-looking statements included in this MD&A should not be unduly relied upon. These forward-looking statements are provided to allow readers to better understand our business and prospects.

In particular, this MD&A contains forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs and the related sensitivities of distributions;
- supply and demand for oil and natural gas;
- expectations for industry drilling levels and drilling activity on our royalty lands;
- expectations regarding the ability to raise capital, including DRIP participation, and add reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditure programs.

Our actual results could differ materially from those anticipated in these forward-looking statements because of many factors, the most significant of which are as follows:

- volatility in market prices for oil and natural gas;
- currency fluctuations;
- changes in income tax laws or changes in tax laws, regulations, royalties, or incentive programs relating to the oil and gas industry and income trusts;
- uncertainties or imprecision associated with estimating oil and natural gas reserves;
- stock market volatility and our ability to access sufficient capital from internal and external sources;
- a significant or prolonged downturn in general economic conditions or industry activity;
- incorrect assessments of the value of acquisitions;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- geological, technical, drilling, and processing problems;
- environmental risks and liabilities inherent in oil and natural gas operations; and
- other factors discussed under Business Risks and Mitigating Strategies in this MD&A, and under Risk Factors and elsewhere in our AIF.

Readers are cautioned that the foregoing list of factors is not exhaustive.

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things, the following:

- future oil and natural gas prices;
- future capital expenditure levels;
- future production levels;
- future exchange rates;
- expected participation in our DRIP;
- the cost of developing and expanding our assets;
- our ability and the ability of our industry partners and royalty payors to obtain equipment in a timely manner to carry out development activities;
- our ability to market our oil and natural gas successfully to current and new customers;
- the impact of increasing competition;
- our ability to obtain financing on acceptable terms; and
- our ability to add production and reserves through our development and acquisition activities.

The Outlook section sets forth our key operating assumptions with respect to the forward-looking statements contained in this MD&A.

The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement and speak only as of the date of this MD&A. Our policy for updating forward-looking statements is to update our key operating assumptions quarterly and, except as required by law, we do not undertake to update any other forward-looking statements.

Non-GAAP Measures

Within this MD&A, references are made to terms commonly used as key performance indicators in the oil and gas industry. We believe that operating netback, funds generated from operations, and net debt to funds generated from operations are useful supplemental measures for management and investors to analyze operating performance, financial leverage, and liquidity, and we use these terms to facilitate the understanding and comparability of our results of operations and financial position. However, these terms do not have any standardized meanings prescribed by Canadian GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

Operating netback, which is calculated as average unit sales price less royalties and operating expenses, represents the cash margin for product sold, calculated on a per boe basis (see Operating Netback).

Funds generated from operations is a financial term commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital and is a key measure of our ability to generate cash, finance operations, and pay monthly distributions. Funds generated from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with Canadian GAAP. The key difference between cash provided by operating activities and funds generated from operations is changes in non-cash working capital, which is affected by accounts receivable and accounts payable and accrued liabilities. Accounts receivable, and therefore working capital, can fluctuate greatly between reporting periods due to timing of receipt of payments. In the event that commodity prices and/or volumes have changed significantly from the previous reporting period, a significant difference could occur between cash provided by operating activities and funds generated from operations. All references to funds generated from operations throughout this report are based on cash provided by operating activities before changes in non-cash working capital as per the Consolidated Statements of Cash Flows. Funds generated from operations per Trust Unit is calculated based on the weighted average number of Trust Units outstanding consistent with the calculation of net income per Trust Unit (see Liquidity and Capital Resources – Operating Activities).

Net debt to funds generated from operations is calculated as net debt (total debt adjusted for working capital) as a proportion of funds generated from operations for the previous 12 months (see Debt Analysis).

In addition, we refer to various per boe figures, such as revenues and costs, also considered non-GAAP measures, which provide meaningful information on our operational performance. We derive per boe figures by dividing the relevant revenue or cost figure by the total volume of oil and natural gas production during the period, with natural gas converted to equivalent barrels of oil as described below.

Conversion of Natural Gas to Barrels of Oil Equivalent (boe)

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (boe). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation.

Management's Report

Management has prepared the accompanying consolidated financial statements of Freehold Royalty Trust in accordance with Canadian generally accepted accounting principles.

Management is responsible for the accuracy and integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and reliable accounting records are produced for financial reporting purposes.

External auditors, KPMG LLP, were appointed by the Unitholders to perform an examination of the corporate and accounting records so as to express an opinion on the consolidated financial statements of Freehold Royalty Trust. Their examination included tests and procedures considered necessary to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the audit committee, all of whose members are independent directors of Freehold Resources Ltd. The committee meets with management and the independent auditors to ensure that management's responsibilities are properly discharged.

William O. Ingram
President and Chief Executive Officer
March 3, 2010

Darren G. Gunderson
Vice-President, Finance and Chief Financial Officer

Auditors' Report

To the Unitholders of Freehold Royalty Trust:

We have audited the consolidated balance sheets of Freehold Royalty Trust as at December 31, 2009 and 2008 and the consolidated statements of income, comprehensive income and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2009 and 2008, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KPMG LLP
Chartered Accountants
Calgary, Canada
March 3, 2010

Consolidated Balance Sheets

($000s)	December 31 2009	December 31 2008
Assets		
Current assets:		
Cash	$ 432	$ 537
Accounts receivable	24,056	23,261
	24,488	23,798
Reclamation fund (note 5)	2,261	1,827
Deferred long-term compensation (note 8)	1,954	120
Petroleum and natural gas interests (note 3)	389,837	426,530
	$ 418,540	$ 452,275
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	$ 8,050	$ 29,676
Accounts payable and accrued liabilities	17,877	14,094
Current portion of unit based and other compensation payable (note 8)	1,643	83
	27,570	43,853
Asset retirement obligation (note 5)	7,160	5,663
Unit based and other compensation payable (note 8)	3,702	243
Long-term debt (note 4)	45,000	140,000
Future income tax liability (note 9)	36,136	42,511
Unitholders' equity:		
Unitholders' capital (note 6)	684,979	567,310
Contributed surplus (note 8)	759	722
Deficit	(386,766)	(348,027)
	298,972	220,005
	$ 418,540	$ 452,275

See accompanying notes to consolidated financial statements.

Approved on behalf of Freehold Royalty Trust by Freehold Resources Ltd., as Administrator:

D. Nolan Blades
Director

Rodger A. Tourigny
Director

Consolidated Statements of Income, Comprehensive Income and Deficit

			Year Ended December 31	
($000s, except per unit and weighted average data)		**2009**		2008
Revenue:				
Royalty income and working interest sales	**$**	**119,965**	$	204,116
Royalty expense and mineral tax		**(2,733)**		(6,616)
		117,232		197,500
Other income (note 13)		**2,122**		-
Expenses:				
Operating		**11,655**		11,299
General and administrative		**7,234**		6,790
Unit based and other compensation (note 8)		**3,718**		97
Interest and financing		**4,678**		7,039
Depletion and depreciation		**63,060**		67,948
Accretion of asset retirement obligation (note 5)		**333**		384
Management fee (note 7)		**2,018**		2,482
		92,696		96,039
Income before taxes		**26,658**		101,461
Income and capital taxes (note 9)		**255**		398
Future income tax reduction (note 9)		**(5,338)**		(8,893)
		(5,083)		(8,495)
Net income and comprehensive income		**31,741**		109,956
Deficit, beginning of year		**(348,027)**		(314,234)
Distributions declared		**(70,480)**		(143,749)
Deficit, end of year	**$**	**(386,766)**	$	(348,027)
Net income per Trust Unit, basic and diluted	**$**	**0.63**	$	2.23
Weighted average number of Trust Units:				
Basic		**49,999,617**		49,370,878
Diluted		**50,053,435**		49,412,670

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

		Year Ended December 31
($000s)	**2009**	2008
Cash provided by (used in):		
Operating:		
Net income	**$ 31,741**	$ 109,956
Items not involving cash:		
Depletion and depreciation	**63,060**	67,948
Unit based and other compensation	**3,444**	7
Future income tax reduction	**(5,338)**	(8,893)
Accretion of asset retirement obligation	**333**	384
Trust Units issued in lieu of management fee	**2,018**	2,482
Expenditures on reclamation	**(173)**	(602)
	95,085	171,282
Changes in non-cash working capital (note 12)	**574**	7,970
	95,659	179,252
Financing:		
Issue of Trust Units, net of issue costs	**110,486**	-
Long-term debt	**(95,000)**	(38,000)
Distributions paid	**(88,200)**	(121,471)
	(72,714)	(159,471)
Investing:		
Property and royalty acquisitions	**(9,539)**	(7,693)
Capital expenditures	**(15,491)**	(12,992)
Change in reclamation fund	**(434)**	(39)
Changes in non-cash working capital (note 12)	**2,414**	1,087
	(23,050)	(19,637)
Increase (decrease) in cash	**(105)**	144
Cash, beginning of year	**537**	393
Cash, end of year	**$ 432**	$ 537

See accompanying notes to consolidated financial statements.

Notes to the Consolidated Financial Statements

Years ended December 31, 2009 and 2008

Basis of Presentation

Freehold Royalty Trust (Freehold or the Trust) is an open-ended investment trust formed under the laws of the Province of Alberta pursuant to a Trust Indenture dated September 30, 1996 as amended from time to time. The Trust holds royalty interests directly and a 99% royalty interest in the funds generated by its wholly owned subsidiary, Freehold Resources Ltd. (Freehold Resources). Freehold Resources was incorporated on June 3, 1996 and derives its income from certain petroleum and natural gas working interest properties. The Trust also holds royalty interests and working interests through Petrovera Resources (Petrovera), a general partnership acquired on May 10, 2005.

These consolidated financial statements include the accounts of the Trust, Freehold Resources and Petrovera. All inter-entity transactions have been eliminated.

1. Significant Accounting Policies

(a) Petroleum and Natural Gas Interests

The Trust follows the full cost method of accounting. All costs of acquiring, exploring for and developing oil and gas and related reserves are capitalized. Such costs include land acquisition, geological and geophysical, carrying charges of unproved properties, costs of drilling both productive and non-productive wells, directly related administrative costs and asset retirement costs. Costs are reduced by proceeds from the sale of oil and gas properties. Gains and losses are not recognized upon disposition of oil and gas properties unless such a disposition would alter the rate of depletion by 20% or more.

(b) Ceiling Test

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties. The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved interests and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(c) Depletion

Oil and gas interests and royalty interests, including the costs of production equipment, future capital costs associated with proved reserves, and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. Reserves are converted to equivalent units on the basis of relative energy content.

(d) Asset Retirement Obligation

The Trust recognizes the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

(e) *Income and Other Taxes*

The Trust is a taxable trust under the Income Tax Act (Canada) and it distributes substantially all of its taxable income to its Unitholders. The tax deductions received by the Trust for the distributions to Unitholders represent an exemption from taxation equivalent to the Trust's earnings.

The Trust follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. Freehold Resources can deduct royalty payments to the Trust in determining taxable income and is generally liable for income taxes on its 1% residual interest.

(f) *Use of Estimates*

The preparation of financial statements in accordance with Canadian generally accepted accounting principles (Canadian GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses during the reporting period. Actual results could differ as a result of using estimates.

The amounts recorded for depletion of petroleum and natural gas properties and asset retirement obligations and amounts used in ceiling test calculations, are based on estimates of petroleum and natural gas reserves and future costs to develop those reserves. By their nature, these estimates of reserves, costs, and related future cash flows are subject to uncertainty, and the impact on the financial statements of future periods could be material.

The Trust follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of future income tax may be greater than or less than the estimates and the differences may be material.

(g) *Unit Based and Other Compensation Plans*

The Trust funds its proportionate share of the costs associated with a long-term incentive compensation plan for employees of Rife Resources, the Manager of the Trust (the Manager's LTIP). The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional rights on the date of distribution. Since participants in the Manager's LTIP receive a cash payment on a fixed vesting date, a liability is determined based on the fair value of the rights at each period end. The valuation incorporates the period end Trust Unit price, the number of rights outstanding at each period end, and certain management assumptions. Compensation expense is recognized over the vesting period with the portion of the liability not yet expensed treated as a deferred asset. The Trust has not incorporated an estimated forfeiture rate for rights that will not vest; rather, the Trust accounts for actual forfeitures as they occur.

A deferred trust unit plan has been established for the non-management directors of Freehold whereby fully-vested deferred trust units are granted annually. Under this plan, distributions to Unitholders declared prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. Compensation expense is recognized at the market value of the Trust Units at the time of grant or distribution with a corresponding increase to contributed surplus. Upon redemption of the deferred trust units for Trust Units, the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' capital.

The Trust funds its proportionate share of a retirement benefit for certain employees of the Manager, upon fulfilling certain criteria. The Trust accrues its share of the post retirement costs over the service life of the employees.

(h) *Net Income Per Trust Unit*

Basic Trust Units outstanding are the weighted average number of Trust Units outstanding for each period. Diluted Trust Units outstanding are calculated using the treasury stock method, which assumes that any proceeds received from options with a market value in excess of option price would be used to buy back Trust Units at the average market price for the period.

(i) *Revenue Recognition*

Revenue from the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Trust, or the operator of the Trust's royalty properties, to its customers.

(j) *Financial Instruments*

All financial instruments, including all derivatives, are to be recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities except those held-for-trading and available-for-sale are measured at amortized cost determined using the effective interest rate method. Held-for-trading financial assets are measured at fair value with changes in fair value recognized in earnings. Available for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to earnings when derecognized or impaired.

Cash, reclamation fund, and short-term investments, if any, are held-for-trading investments, and the fair values approximate their carrying value due to their short-term nature. Accounts receivable are classified as loans and receivables, and accounts payable and accrued liabilities and long-term debt are classified as other financial liabilities. The fair values of accounts receivable and accounts payable and accrued liabilities approximate their carrying values due to the short-term nature of these instruments. The Trust has not designated any financial instruments as available-for-sale or held-to-maturity.

The Trust did not identify any material embedded derivatives which required separate recognition and measurement.

2. New Accounting Standards

(a) *Financial Instruments - Disclosures*

In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862, *Financial Instruments – Disclosures*, to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Trust on December 31, 2009 (see Long-Term Debt, note 4).

(b) *International Financial Reporting Standards*

In January 2006, the Canadian Accounting Standards Board (AcSB) adopted a strategic plan for the direction of accounting standards in Canada. As part of the AcSB's strategic plan, Canadian publicly accountable entities will be required to report under International Financial Reporting Standards (IFRS), which will replace Canadian GAAP. In October 2009, the AcSB confirmed January 1, 2011 as the changeover date to commence reporting under IFRS.

3. Petroleum and Natural Gas Interests

($000s)		2009		2008
Petroleum and natural gas interests	$	902,976	$	876,609
Accumulated depletion and depreciation		(513,139)		(450,079)
Petroleum and natural gas interests, net	$	389,837	$	426,530

The depletion calculation included $0.9 million (2008 – $1.2 million) for estimated future development costs associated with proved undeveloped reserves and excluded $27.6 million (2008 – $33.9 million) for the lower of cost and market value of unproved lands.

The Trust's ceiling test calculation, performed at December 31, 2009, resulted in no impairment loss. The future prices used by the Trust in estimating cash flows were based on forecasts by an independent qualified reserves evaluator, adjusted for the Trust's quality, transportation, and contract differences. The following table summarizes the benchmark prices used in the calculation.

Year	WTI Crude Oil (US$/bbl)	Foreign Exchange Rate (US$/Cdn$)	Edmonton Par Crude Oil (Cdn$/bbl)	AECO Natural Gas (Cdn$/MMBtu)
2010	79.17	0.92	84.25	5.36
2011	84.46	0.92	89.99	6.21
2012	86.89	0.92	92.61	6.44
2013	90.20	0.92	96.19	7.23
2014	92.01	0.92	98.13	7.98
Average annual increase, thereafter	2%	-	2%	2%

4. Long-Term Debt

Freehold has a $195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which $45 million was drawn at December 31, 2009. In addition, Freehold has available a $15 million extendible revolving operating facility.

The facilities are secured with $300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice. The facilities are extendible annually with the latest review completed in May 2009. In the event that the lenders do not consent to an extension, the revolving credit facility would revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period, which is May 2010.

Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 250 to 400 basis points, and standby fees. The fair value of the long-term debt was determined using quoted borrowing rates and therefore was considered Level 2. At December 31, 2009, the fair value of the long-term debt approximated its carrying value. The average effective interest rate on advances under the credit facility for the year ended December 31, 2009 was 2.4% (2008 – 4.3%).

Freehold's borrowing base is dependent on our lenders' annual review and interpretation of our reserves and future commodity prices, with the next renewal to occur by May 2010.

5. Asset Retirement Obligation

The Trust has no asset retirement obligation on its royalty interest properties. The Trust's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of the Trust's total asset retirement obligation is estimated to be $7.2 million (discounted at a weighted average credit adjusted risk free rate of 5.8%), with the undiscounted value being $25.6 million. Payments to settle the obligations are expected to occur continuously over the next 60 years, with the majority of obligations being more than 15 years away.

($000s)		**2009**		2008
Balance, beginning of year	**$**	**5,663**	$	6,608
Liabilities incurred		**485**		381
Liabilities settled		**(173)**		(602)
Revision in estimates [1]		**852**		(1,108)
Accretion expense		**333**		384
Balance, end of year	**$**	**7,160**	$	5,663

(1) Revision in estimates is mainly a result of an increase in the inflation rate and changes to abandonment years.

A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. All liabilities settled during the periods are paid from the reclamation fund.

6. Unitholders' Capital

The Trust has authorized an unlimited number of Trust Units of which 57,502,943 were issued and outstanding at December 31, 2009 (2008 – 49,459,429).

Trust Units Issued and Outstanding

		2009		2008
	Number	**Amount ($000s)**	Number	Amount ($000s)
Balance, beginning of year	**49,459,429**	**$ 567,310**	49,316,813	$ 564,828
Issued in lieu of management fee (note 7)	**148,597**	**2,018**	142,616	2,482
Issued for deferred trust unit plan (note 8)	**15,427**	**222**	-	-
Issued for distribution reinvestment plan	**260,740**	**3,906**	-	-
Issued for equity offering	**7,618,750**	**115,424**	-	-
Issue costs, net of tax effect	**-**	**(3,901)**	-	-
Balance, end of year	**57,502,943**	**$ 684,979**	49,459,429	$ 567,310

On December 10, 2009, Freehold closed an equity offering and issued 7,618,750 units at a price of $15.15 per Trust Unit for gross proceeds of $115.4 million. The issue costs including underwriters fees were $4.9 million ($3.9 million net of tax effect) with net proceeds being $110.5 million.

On October 26, 2009, the Board of Directors approved the monthly issuance of Trust Units from treasury for the distribution reinvestment plan (DRIP), effective for the distribution payable on November 15, 2009 and thereafter. Previously, Trust Units issued in relation to the DRIP were purchased through the facilities of the Toronto Stock Exchange at prevailing market prices.

In May 2006, the Trust reserved an additional 800,000 Trust Units pursuant to its management agreement with the Manager, of which 464,506 have been issued. The Trust has reserved 200,000 Trust Units pursuant to the deferred trust unit plan, of which 15,427 have been issued. In addition, the Trust has reserved 500,000 Trust Units pursuant to the DRIP, of which 260,740 have been issued.

The Trust is an open-ended mutual fund under which Unitholders have the right to request redemption directly from the Trust. Pursuant to the Amended and Restated Trust Indenture, Trust Units tendered by holders are subject to redemption under certain terms and conditions including the determination of the redemption price at the lower of the closing market price on the Toronto Stock Exchange on the date the Trust Units are tendered for redemption or 90% of the weighted average trading price for the 10-day trading period commencing on the tender date. Cash payments for Trust Units tendered for redemption are limited to $100,000 per month.

7. Related Party Transactions

The Trust does not have any employees. The Manager of the Trust is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). The Manager recovers its general and administrative, long-term incentive plan and retirement benefit costs and receives a quarterly management fee paid in Trust Units.

The Manager provides certain services for a fee based on a specified number of Trust Units per quarter, pursuant to a management agreement which has a term of three years and will be renewed on November 26, 2010 unless terminated. During 2009, the management fee paid was 148,597 Trust Units with an ascribed value of $2.0 million (2008 – 142,616 Trust Units with an ascribed value of $2.5 million).

For the year ended December 31, 2009, the Manager charged the Trust $5.7 million (2008 – $5.3 million) in general and administrative costs. The transactions were in the normal course of operations and were measured at the exchange amount, which was the amount of consideration established and agreed to by the Trust and the Manager.

8. Unit Based and Other Compensation

(a) Manager's LTIP

The Trust participates in its proportionate share of a long-term incentive compensation plan for all employees of the Manager (the Manager's LTIP). The Manager's LTIP will result in employees receiving cash compensation in relation to the value of a specified number of notional units. The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions made by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. Upon vesting, the employee is entitled to a cash payout based on the Trust Unit price. In addition, there is a performance multiplier based in part on the Trust's performance over the vesting period, which may range from 0.25 to 1.5 times the market value.

The total expensed for the year ended December 31, 2009 was $2,862,000 (2008 – $203,000 recovered). At December 31, 2009, Freehold recorded $1,954,000 (2008 – $120,000) as a deferred long-term compensation asset representing the portion of the liability not yet charged to earnings. In addition, Freehold accrued $3,395,000 (2008 – $243,000) as a long-term liability and $1,545,000 (2008 – $83,000) as a current liability.

(b) Deferred Trust Unit Plan

Fully-vested deferred trust units are granted annually to non-management directors. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. As at December 31, 2009, there were 53,070 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

Deferred Trust Units

	2009	2008
Balance, beginning of year	**44,087**	30,473
Annual grants	**22,577**	12,540
Units redeemed on a Director's retirement	**(22,038)**	-
Units cancelled	**-**	(4,505)
Prior years adjustment	**-**	(311)
Additional units resulting from distributions	**8,444**	5,890
Balance, end of year	**53,070**	44,087

For the year ended December 31, 2009, 22,038 deferred trust units were redeemed upon a director's retirement, resulting in the issuance of 15,427 Trust Units from treasury. In payment of withholding tax, 6,611 deferred trust units were cancelled and the cash value remitted to Canada Revenue Agency.

For the year ended December 31, 2009, the Trust expensed $352,000 as unit based compensation with a corresponding increase to contributed surplus. For the year ended December 31, 2008, the Trust expensed $300,000 as unit based compensation. The corresponding increase to contributed surplus for the year ended December 31, 2008 was $210,000, as $90,000 was a cash expense for the cancellation of deferred trust units.

Contributed Surplus

($000s)		2009		2008
Balance, beginning of year	**$**	**722**	$	512
Trust Unit incentive compensation expense		**352**		210
Deferred trust units redeemed on a Director's retirement		**(315)**		-
Balance, end of year	**$**	**759**	$	722

*(c) **Retirement Benefit***

During 2009 the Trust agreed to participate in its proportionate share of a retirement benefit for certain employees of the Manager. The retirement benefit is payable in four equal instalments upon retirement and reaching the age of 65. Service costs are amortized on a straight-line basis over the expected average remaining service lifetime.

Reconciliation of the changes in the plan's benefit obligations for the year 2009:

($000s)		2009		2008
Accrued benefit obligation, beginning of year	**$**	**-**	$	-
Current service cost		**504**		-
Payments		**(99)**		-
Accrued benefit obligation, end of year	**$**	**405**	$	-

9. Income Taxes

The Trust uses the asset and liability method of accounting for income taxes, as described in note 1(e). The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to the Trust's earnings before income taxes. This difference results from the following items:

($000s, except as noted)		2009		2008
Income before income taxes and capital taxes	$	26,658	$	101,461
Combined federal and provincial tax rate		29.4%		30.0%
Computed expected income tax expense	$	7,834	$	30,421
Increase (decrease) in income tax resulting from:				
Non-taxable earnings of the Trust		(16,437)		(40,803)
Benefit of future rate reductions		3,151		1,273
Unit based and other compensation		104		90
Capital taxes		255		398
Other		10		126
Total income and capital taxes	$	(5,083)	$	(8,495)

The components of future income taxes at December 31 are as follows:

($000s)		2009		2008
Future income tax liabilities:				
Petroleum and natural gas interests	$	38,746	$	44,023
Future income tax assets:				
Asset retirement obligation		(1,855)		(1.512)
Trust unit issue expense		(755)		-
Net future income tax liability	$	36,136	$	42,511

On a consolidated basis, the Trust's carrying value for book purposes exceeds the amount available for tax purposes by $176 million.

The Trust's future tax liability relates primarily to the situation whereby its assets have a high book value relative to their associated tax value. This results in significant taxable temporary differences that reverse over time. Since the SIFT legislation will not take effect until 2011, a portion of the temporary differences will reverse during the period when the tax rate applicable to the assets continues to be nil. The combined federal and provincial tax rate used in the rate reconciliation is higher than the rate that will apply to the Trust because the SIFT tax will not apply until 2011 and is nil until that time.

10. Capital Management

Freehold Royalty Trust is structured as a mutual fund trust under the Income Tax Act (Canada). This enables us to return the majority of our income to Unitholders in a tax-effective manner. We receive revenue from oil and gas properties as reserves are produced, which is paid to Unitholders on a regular basis over the economic life of the properties. The Trust's objective for managing capital is to maximize long-term Unitholder value by distributing to Unitholders any cash that is not required for financing our operations or capital investment growth opportunities that may offer Unitholders better value.

We define capital as long-term debt, Unitholders' equity, and working capital based on the consolidated financial statements. We manage our capital structure taking into account operating activities, debt levels, debt covenants, capital expenditures, and distribution levels. We also consider changes in economic conditions and commodity prices as well as the risk characteristics of our assets. We have a depleting asset base, and ongoing development activities and acquisitions are necessary to replace production and add additional reserves. From time to time, we may issue Trust Units or adjust capital spending to manage current and projected debt levels.

We retain working capital primarily to fund capital expenditures or acquisitions and reduce bank indebtedness. The Trust's distribution policy includes withholding a portion of cash provided by operating activities for contributions to the Trust's reclamation fund to provide a cash reserve for the eventual abandonment of oil and gas properties.

Our Trust Indenture provides that not more than 49% of the Trust's Units can be held by non-residents of Canada. We monitor foreign ownership levels on a regular basis through declarations from Unitholders and geographical searches. Accordingly, the reported level of Canadian ownership is subject to these limitations, and the level of Canadian ownership can change at any time without notice.

As a result of the Canadian trust taxation legislation passed in June 2007 and effective January 1, 2011, the Trust is subject to certain capital growth restrictions referred to as "normal growth" equity guidelines. These guidelines limit the amount of Unitholders' capital that can be issued by the Trust in each of the next three years, based on the Trust's market capitalization on October 31, 2006. Our market capitalization as of the close of trading on October 31, 2006 was approximately $929 million, which means our safe harbour equity growth amount for calendar 2008 was $557 million, and for each of calendar 2009 and 2010 is an additional $186 million with an ultimate total equity growth amount of no more than $929 million. In 2009, the Trust issued 8,043,514 Trust Units from treasury with an ascribed value of $117 million, which is well within the "normal growth" equity guidelines.

We are bound by covenants on our credit facilities. The covenants are monitored monthly as part of management's internal review to ensure compliance with the requirements. Under our credit facility, we are restricted from making distributions if we are or would be in default under the credit facility or if our borrowings thereunder exceed our borrowing base, currently set at $210 million. As at December 31, 2009, the Trust was in compliance with all such covenants.

Capitalization

($000s, except as noted)	**2009**	2008
Unitholders' equity	**$ 298,972**	$ 220,005
Long term debt	**45,000**	140,000
Working capital deficiency	**3,082**	20,055
Net debt	**48,082**	160,055
Cash provided by operating activities for last 12 months	**95,659**	179,252
Change in non-cash working capital	**(574)**	(7,970)
Trailing 12 months funds generated from operations	**95,085**	171,282
Net debt to trailing 12 months funds generated from operations (times)	**0.5**	0.9

11. Financial Instrument Risk Management

The Trust has exposure to credit, liquidity, and market risks from its use of financial instruments. We employ the following strategies to mitigate these risks.

(i) Credit risk

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from our receivables. A large part of our accounts receivable are with oil and gas industry operators, either as joint venture partners or as payors of various royalty agreements. Our diversified revenue stream limits the size of any one property or industry operator with respect to total receivables.

We maintain an aggressive auditing program to ensure that we are paid royalties on our production from our lands in accordance with the terms of the various leases and royalty agreements.

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure. We did not have an allowance for doubtful accounts as at December 31, 2009 and December 31, 2008 and did not provide for any doubtful accounts nor were we required to write off any receivables during the year ended December 31, 2009 or the years ended December 31, 2008 and 2007.

The Trust markets approximately 60% of its production along with the operator or royalty payor under the terms of a diverse number of agreements. When it can, the Trust takes its production in kind (approximately 40%) and sells to two primary purchasers with a proven history in the industry.

(ii) Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We maintain a conservative approach to debt management that aims to provide maximum financial flexibility with respect to acquisitions and development expenditures, while maintaining stable distributions. At December 31, 2009, there was $165 million of available capacity under our credit facilities. As circumstances warrant, we allocate a portion of cash provided by operating activities to debt repayment. We prepare annual capital expenditure budgets, which are regularly monitored and updated.

(iii) Market risk

Market risk is the risk that changes in market prices, such as foreign currency exchange rates, commodity prices, and interest rates, will affect net income or the value of financial instruments. For short-term investments, we select counterparties based on credit ratings and monitor all investments to ensure a stable return, avoiding complex investment vehicles with higher risk such as asset-backed commercial paper.

FOREIGN CURRENCY EXCHANGE RATE RISK

We do not sell or transact in any foreign currency; however, the underlying market prices in Canada for oil and natural gas are influenced by changes in the exchange rate between the Canadian and U.S. dollar. During the year ended December 31, 2009, we had no foreign exchange related derivative contracts in place. Assuming all other variables held constant, a $0.01 change (plus or minus) in the U.S./Canadian dollar exchange rate for the year ended December 31, 2009, would have resulted in a corresponding change to net income of approximately $1.3 million (2008 – $2.1 million).

COMMODITY PRICE RISK

Commodity price risk is the risk that the fair value of future cash flows will fluctuate with changes in commodity prices. Commodity prices for oil and natural gas are influenced by the relationship between the Canadian and U.S. dollar as well as macroeconomic events that dictate the levels of supply and demand. During the year ended December 31, 2009, we had no commodity price related derivative contracts in place. Assuming all other variables held constant, a US$1.00 change (plus or minus) in the WTI crude oil price for the year ended December 31, 2009, would have resulted in a corresponding change to net income of approximately $1.5 million (2008 – $1.4 million). A $0.25 change (plus or minus) in the AECO natural gas price would have resulted in a corresponding change to net income of approximately $1.2 million (2008 – $1.5 million).

INTEREST RATE RISK

We are exposed to interest rate risk on outstanding bank debt, which has a floating interest rate, and fluctuations in interest rates would impact our future cash flows. Assuming all other variables held constant, a 1% change (plus or minus) in the interest rate for the year ended December 31, 2009 would have resulted in a corresponding change to net income of approximately $1.5 million (2008 – $1.6 million).

12. Supplemental Cash Flow Disclosure

Changes in Non-Cash Working Capital Balance

($000s)		**2009**		2008
Accounts receivable	**$**	**(795)**	$	3,541
Accounts payable and accrued liabilities		**3,783**		5,516
	$	**2,988**	$	9,057

($000s)		**2009**		2008
Operating	**$**	**574**	$	7,970
Investing		**2,414**		1,087
	$	**2,988**	$	9,057

Cash Expenses Paid

($000s)		**2009**		2008
Interest	**$**	**4,375**	$	6,753
Taxes		**494**		329

13. Contingencies

In May 2009, a statement of claim was filed against the Trust for $9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, the Trust has assessed the claim, believes it has no merit, and intends to aggressively defend itself in the claim. The claim's outcome is not determinable; therefore, no liability has been recorded in the financial statements.

In December 2009, a judgement in the amount of $2.1 million in Freehold's favour was received and recorded in other income. The claim was based on Freehold's assertion of incorrect royalty payments and production from a terminated lease. Cash payment in full was received subsequent to year-end. The defendant has appealed this judgment but Freehold and its legal counsel believe there are no grounds for a successful appeal. The appeal's outcome is not determinable; therefore, no liability has been recorded in the financial statements.

14. Subsequent Event

On February 17, 2009, Freehold closed an acquisition of certain royalty interests in Alberta, Saskatchewan and British Columbia for $39 million, after closing adjustments. The acquisition was effective October 1, 2009 and was funded through existing credit facilities.

Ten-Year Historical Review

	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000
Financial ($000s, except as noted)										
Gross revenue	**119,965**	204,116	152,184	143,067	136,914	78,491	73,166	63,143	61,885	64,500
Net income (loss) (1)	**31,741**	109,956	(1,192)	45,181	58,346	36,892	37,078	27,529	27,304	31,758
Per Trust Unit ($)	**0.63**	2.23	(0.02)	0.92	1.36	1.17	1.19	0.91	0.95	1.19
Funds generated from operations (2)	**95,085**	171,282	121,008	119,849	118,034	64,313	60,658	51,489	49,728	51,882
Per Trust Unit ($)	**1.90**	3.47	2.46	2.44	2.76	2.04	1.95	1.71	1.72	1.94
Distributions declared	**70,480**	143,749	94,545	103,100	84,810	54,490	53,149	39,530	45,264	35,226
Per Trust Unit ($)	**1.40**	2.91	1.92	2.10	1.92	1.73	1.70	1.31	1.56	1.32
Capital expenditures	**15,491**	12,992	12,167	11,446	7,982	5,823	5,894	2,946	2,992	5,161
Net acquisitions	**9,539**	7,693	90,456	5,382	351,705	13,061	3,386	2,326	29,707	5,326
Long-term debt	**45,000**	140,000	178,000	100,000	107,000	27,000	18,000	30,000	33,000	38,000
Unitholders' equity	**298,972**	220,005	251,106	344,448	399,471	164,822	180,992	185,326	196,317	182,898
Operating										
Production (boe/d)	**7,302**	7,804	8,484	8,412	7,636	5,588	5,817	6,004	6,086	5,523
Average sales price ($/boe)	**44.00**	69.93	48.63	46.07	48.53	37.91	34.01	28.44	27.63	31.39
Operating netback ($/boe) (2)	**39.61**	65.18	43.54	42.64	45.49	34.05	30.51	25.43	24.30	28.26
Land (gross acres) (000s)	**2,386**	2,375	2,380	2,069	2,006	1,067	1,011	1,001	1,005	872
Reserves (Mboe) (3)	**24,054**	25,374	27,963	28,012	30,530	21,163	22,052	26,813	28,177	28,150
Net asset value ($/Trust Unit) (4)	**13.06**	13.92	11.85	11.65	13.85	8.92	8.08	8.74	7.51	8.65
Reserve life index (years)	**9.7**	9.8	9.5	9.6	9.9	10.6	11.0	12.2	12.7	14.0
Trust Units										
High ($)	**17.00**	24.40	15.85	23.06	19.30	18.42	17.19	11.35	10.10	9.50
Low ($)	**6.87**	9.15	12.51	12.43	14.25	14.02	10.50	9.00	8.00	5.60
Close ($)	**15.09**	10.49	15.60	14.81	18.81	17.45	16.35	10.88	9.20	8.70
Volume (000s)	**30,024**	36,469	25,101	35,512	28,320	11,567	10,970	7,323	8,162	6,752
Outstanding (millions)										
At period end	**57.5**	49.5	49.3	49.2	49.0	31.5	31.5	30.2	30.1	26.7
Weighted average	**50.0**	49.4	49.2	49.1	42.8	31.5	31.2	30.2	28.8	26.7

(1) 2003 and prior years were restated in 2004 for the adoption of new Canadian standards for asset retirement obligations.

(2) See Non-GAAP measures on page 45.

(3) Net proved plus probable reserves for 2003 through 2008. Reserves for prior years are gross established and are not directly comparable due to a change in reserves definitions and evaluation methodology in 2003.

(4) Net asset value (NAV) is a measure used widely within the investment community and in the oil and natural gas industry. It shows what is normally referred to as a 'produce-out' NAV calculation under which the Trust's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It does not represent a 'going concern' value and it should not be assumed that the present value of oil and gas reserves represent the fair market value of the reserves. Net asset value does not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

Board of Directors

D. Nolan Blades, Calgary, Alberta
Director since 1996
Chair of the Board
Committees: Audit, Corporate SIFT Tax Strategy (Chair), and Compensation

Nolan Blades is President of Sunny Gables Holdings Ltd. (Calgary). He holds a Bachelor of Science degree in Mechanical Engineering and is a Professional Engineer. Mr. Blades was President and CEO of Pursuit Resources Corp. from 1993 to 2000, prior to which he held senior executive positions with Chauvco Resources Ltd. and Oakwood Petroleum Ltd.

Harry S. Campbell, Q.C. Calgary, Alberta
Director since 1996
Committees: Corporate SIFT Tax Strategy, Governance, and Reserves

Harry Campbell is Vice-Chair of the law firm Burnet, Duckworth & Palmer LLP (Calgary). He was admitted to the Alberta Bar in 1974 and has extensive experience with Canadian oil and gas transactions and international petroleum and natural gas matters.

Tullio Cedraschi, Montreal, Quebec
Director since 1998
Committees: Corporate SIFT Tax Strategy and Governance

Tullio Cedraschi is a Corporate Director and former President and CEO of the CN Investment Division (Montreal). He is Governor Emeritus of McGill University, and Governor of the National Theatre School of Canada. He holds an MBA from McGill University.

Peter T. Harrison, Montreal, Quebec
Director since 1996
Committees: Reserves

Peter Harrison is Manager, North American Equities for the CN Investment Division (Montreal). Previously he was Senior Vice-President of Montrusco Bolton Inc. He holds a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario and is a Chartered Financial Analyst.

William O. Ingram, Calgary, Alberta
Director since 2009

William Ingram is President and CEO of Freehold Resources Ltd. and Rife Resources Ltd. (Calgary). Prior to joining Rife in 1984, he held senior engineering positions with Amoco Canada Petroleum Company Ltd. Mr. Ingram holds a Bachelor of Science degree in Chemical Engineering from the University of Alberta and is a Professional Engineer.

P. Michael Maher, Calgary, Alberta
Director since 1996
Committees: Audit, Compensation (Chair), and Governance (Chair)

Michael Maher is a Professional Engineer, Professor and former Dean of the Haskayne School of Business, University of Calgary. He holds a Bachelor of Science degree in Engineering from the University of Saskatchewan, an MBA from the University of Western Ontario, a Ph.D. from Northwestern University, and a Doctor of Commerce degree (honoris causa) degree from St. Mary's University.

David J. Sandmeyer, Calgary, Alberta
Director since 1996
Committees: Corporate SIFT Tax Strategy, and Reserves (Chair)

David Sandmeyer is a Corporate Director and former President and CEO of Freehold Resources Ltd. and Rife Resources Ltd. (Calgary). Prior to joining Rife in 1982, he held senior positions with Amoco Canada Petroleum Company Ltd. A graduate of the University of Saskatchewan, he holds a Bachelor of Science degree in Mechanical Engineering and is a Professional Engineer.

Rodger A. Tourigny, Calgary, Alberta
Director since 2009
Committees: Audit (Chair), Compensation, and Corporate SIFT Tax Strategy

Rodger Tourigny is President of Tourigny Management Ltd., a private consulting company (Calgary). He has been providing consulting services since 1979 primarily dealing with oil and gas, financial services and real estate. He holds a Bachelor of Commerce degree from the University of Saskatchewan and is a Chartered Accountant.

Corporate Information

Officers

D. Nolan Blades
Chair of the Board

William O. Ingram
President and Chief Executive Officer

Michael J. Okrusko
Senior Vice-President,
Special Projects

Garry W. Bieber
Vice-President, Production

J. Frank George
Vice-President, Exploitation

Darren G. Gunderson
Vice-President, Finance and
Chief Financial Officer

Michael J. Stone
Vice-President, Land

Michael J. Mogan
Controller

Karen C. Taylor
Manager, Investor Relations and
Corporate Secretary

The Manager

Rife Resources Ltd.
Website www.rife.com

Auditors

KPMG LLP

Bankers

CIBC
Royal Bank of Canada
The Toronto-Dominion Bank

Legal Counsel

Burnet, Duckworth & Palmer LLP

Independent Engineers

Trimble Engineering Associates Ltd.

Trustee and Transfer Agent

Computershare Trust Company
of Canada
Toll-Free: 1.800.564.6253
Telephone: 1.514.982.7555
Website: www.computershare.com

Trading

Toronto Stock Exchange
Symbol: FRU.UN

Head Office

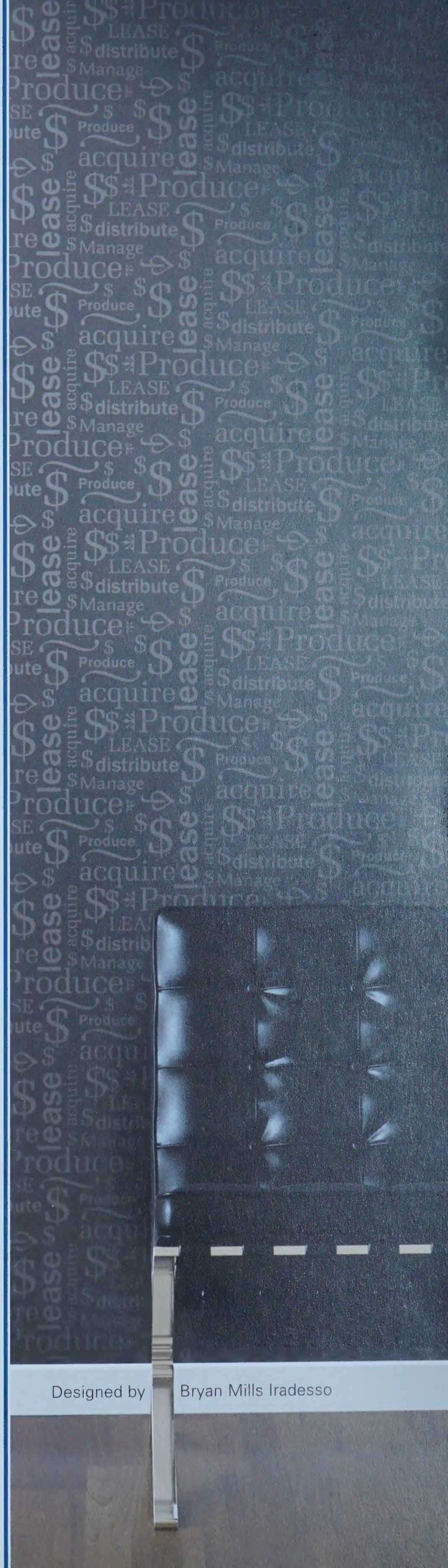
400, 144 – 4th Avenue S.W.
Calgary, Alberta T2P 3N4
Telephone: 403.221.0802
Fax: 403.221.0888

Investor Relations

Toll-Free: 1.888.257.1873
Telephone: 403.221.0891
Fax: 403.221.0888
Email: ktaylor@rife.com
Website: www.freeholdtrust.com

Annual Meeting

The Annual Meeting of the Unitholders of Freehold will be held at 3:30 p.m. (MDT) on Wednesday, May 12, 2010 at the Sun Life Plaza Conference Centre, Calgary, Alberta.



Freehold

ROYALTY TRUST

400, 144 – 4th Avenue SW
Calgary, Alberta T2P 3N4

www.freeholdtrust.com